OTTER TAIL CORP
Form 10-Q
May 12, 2008

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

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2008

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________to__________

Commission file number 0-368

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

Minnesota	41-0462685
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
215 South Cascade Street, Box 496, Fergus Falls, Minnesota	56538-0496
(Address of principal executive offices)	(Zip Code)

866-410-8780

(Registrant s telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller reporting company o

(Do not check if a smaller reporting company)

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

Indicate the number of shares outstanding of each of the issuer s classes of Common Stock, as of the latest practicable date:

April 30, 2008 30,056,148 Common Shares ($5 par value)

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)
-Assets-

	March 31, 2008	December 31, 2007
	(Thousands of dollars)	
Current Assets		
Cash and Cash Equivalents	$ 9,447	$ 39,824
Accounts Receivable:		
Trade Net	148,123	151,446
Other	9,832	14,934
Inventories	115,256	97,214
Deferred Income Taxes	7,208	7,200
Accrued Utility and Cost-of-Energy Revenues	23,371	32,501
Costs and Estimated Earnings in Excess of Billings	47,099	42,234
Other	25,910	15,299
Total Current Assets	386,246	400,652
Investments	9,237	10,057
Other Assets	24,679	24,500
Goodwill	99,242	99,242
Other Intangibles Net	20,217	20,456
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	6,770	6,986
Regulatory Assets and Other Deferred Debits	37,157	38,837
Total Deferred Debits	43,927	45,823
Plant		
Electric Plant in Service	1,046,341	1,028,917
Nonelectric Operations	281,897	257,590
Total Plant	1,328,238	1,286,507
Less Accumulated Depreciation and Amortization	517,291	506,744
Plant Net of Accumulated Depreciation and Amortization	810,947	779,763
Construction Work in Progress	64,398	74,261
Net Plant	875,345	854,024
Total	$ 1,458,893	$ 1,454,754

See accompanying notes to consolidated financial statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)
-Liabilities-

	March 31, 2008	December 31, 2007
	(Thousands of dollars)	
Current Liabilities		
Short-Term Debt	$ 122,200	$ 95,000
Current Maturities of Long-Term Debt	3,348	3,004
Accounts Payable	123,178	141,390
Accrued Salaries and Wages	21,040	29,283
Accrued Taxes	12,015	11,409
Other Accrued Liabilities	15,406	13,873
Total Current Liabilities	297,187	293,959
Pensions Benefit Liability	40,035	39,429
Other Postretirement Benefits Liability	30,765	30,488
Other Noncurrent Liabilities	20,658	23,228
Deferred Credits		
Deferred Income Taxes	106,885	105,813
Deferred Tax Credits	18,187	16,761
Regulatory Liabilities	62,986	62,705
Other	316	275
Total Deferred Credits	188,374	185,554
Capitalization		
Long-Term Debt, Net of Current Maturities	342,490	342,694
Class B Stock Options of Subsidiary	1,255	1,255
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2008 and 2007 155,000 Shares	15,500	15,500
Cumulative Preference Shares Authorized 1,000,000 Shares without Par Value; Outstanding None		
Common Shares, Par Value $5 Per Share Authorized 50,000,000 Shares; Outstanding 2008 29,920,120 and 2007 29,849,789	149,601	149,249
Premium on Common Shares	109,713	108,885
Retained Earnings	262,484	263,332
Accumulated Other Comprehensive Income	831	1,181

Total Common Equity	522,629	522,647
Total Capitalization	881,874	882,096
Total	$ 1,458,893	$ 1,454,754

See accompanying notes to consolidated financial statements

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Otter Tail Corporation
Consolidated Statements of Income
(not audited)

	Three months ended March 31, 2008	Three months ended March 31, 2007
	(In thousands, except share and per share amounts)	
Operating Revenues		
Electric	$ 97,505	$ 89,853
Nonelectric	202,732	211,268
Total Operating Revenues	300,237	301,121
Operating Expenses		
Production Fuel Electric	19,904	16,425
Purchased Power Electric System Use	18,986	26,011
Electric Operation and Maintenance Expenses	26,743	26,875
Cost of Goods Sold Nonelectric (excludes depreciation; included below)	165,223	164,659
Other Nonelectric Expenses	34,747	30,758
Depreciation and Amortization	14,913	13,093
Property Taxes Electric	2,624	2,526
Total Operating Expenses	283,140	280,347
Operating Income	17,097	20,774
Other Income	962	273
Interest Charges	6,711	4,868
Income Before Income Taxes	11,348	16,179
Income Taxes	3,118	5,771
Net Income	8,230	10,408
Preferred Dividend Requirements	184	184
Earnings Available for Common Shares	$ 8,046	$ 10,224
Earnings Per Common Share:		
Basic	$ 0.27	$ 0.35
Diluted	$ 0.27	$ 0.34
Average Number of Common Shares Outstanding:		
Basic	29,818,079	29,503,252

Diluted		30,061,865		29,756,904
Dividends Per Common Share	$	0.2975	$	0.2925

See accompanying notes to consolidated financial statements

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Otter Tail Corporation
Consolidated Statements of Cash Flows
(not audited)

	Three months ended March 31, 2008	Three months ended March 31, 2007
	(Thousands of dollars)	
Cash Flows from Operating Activities		
Net Income	$ 8,230	$ 10,408
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	14,913	13,093
Deferred Tax Credits	(385)	(283)
Deferred Income Taxes	3,722	(742)
Change in Deferred Debits and Other Assets	701	1,302
Discretionary Contribution to Pension Plan		(2,000)
Change in Noncurrent Liabilities and Deferred Credits	(1,147)	3,523
Allowance for Equity (Other) Funds Used During Construction	348	
Change in Derivatives Net of Regulatory Deferral	(1,511)	(151)
Stock Compensation Expense	699	572
Other Net	252	42
Cash Provided by (Used for) Current Assets and Current Liabilities:		
Change in Receivables	8,364	(15,574)
Change in Inventories	(18,230)	2,812
Change in Other Current Assets	(3,529)	(23,047)
Change in Payables and Other Current Liabilities	(5,506)	(11,323)
Change in Interest and Income Taxes Payable	433	5,757
Net Cash Provided by (Used in) Operating Activities	7,354	(15,611)
Cash Flows from Investing Activities		
Capital Expenditures	(57,656)	(23,866)
Proceeds from Disposal of Noncurrent Assets	464	5,739
Acquisitions Net of Cash Acquired		(1,965)
Decreases (Increases) in Other Investments	530	(5,449)
Net Cash Used in Investing Activities	(56,662)	(25,541)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash		5,629
Net Short-Term Borrowings	27,200	35,200
Proceeds from Issuance of Common Stock, Net of Issuance Expenses	454	2,787
Payments for Retirement of Common Stock	(2)	(2)
Proceeds from Issuance of Long-Term Debt	1,135	90
Debt Issuance Expenses	(19)	(77)
Payments for Retirement of Long-Term Debt	(984)	(748)
Dividends Paid	(9,077)	(8,828)
Net Cash Provided by Financing Activities	18,707	34,051

Effect of Foreign Exchange Rate Fluctuations on Cash	224	310
Net Change in Cash and Cash Equivalents	(30,377)	(6,791)
Cash and Cash Equivalents at Beginning of Period	39,824	6,791
Cash and Cash Equivalents at End of Period	$ 9,447	$

See accompanying notes to consolidated financial statements

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OTTER TAIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated results of operations for the periods presented. The consolidated financial statements and notes thereto should be read in conjunction with the consolidated financial statements and notes as of and for the years ended December 31, 2007, 2006 and 2005 included in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2007. Because of seasonal and other factors, the earnings for the three months ended March 31, 2008 should not be taken as an indication of earnings for all or any part of the balance of the year.

The following notes are numbered to correspond to numbers on the notes included in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

1. Summary of Significant Accounting Policies

Revenue Recognition

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

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

Some of the operating businesses enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The Company s consolidated revenues recorded under the percentage-of-completion method were 28.2% for the three months ended March 31, 2008 and 25.1% for the three months ended March 31, 2007. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company s wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized.

The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	March 31, 2008	December 31, 2007
Costs Incurred on Uncompleted Contracts	$ 332,816	$ 286,358
Less Billings to Date	(340,527)	(292,692)
Plus Estimated Earnings Recognized	42,717	38,275
	$ 35,006	$ 31,941

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

(in thousands)	March 31, 2008	December 31, 2007
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 47,099	$ 42,234
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(12,093)	(10,293)
	$ 35,006	$ 31,941

Sales of Receivables

In March 2008, a Company subsidiary entered into a three year $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to a third party financial institution on a revolving basis. In compliance with SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows.

Supplemental Disclosures of Cash Flow Information

	Three months ended March 31,	
(in thousands)	2008	2007
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$(20,554)	$ 174
Cash Paid During the Period for:		
Interest (net of amount capitalized)	$ 6,036	$2,449
Income Taxes	$ 750	$1,046

Fair Value Measurements

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

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

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

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

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

(in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Investments of Nonqualified Retirement Savings Retirement Plan	$ 172	$ 10,748		$ 10,920
Cash Surrender Value of Keyman Life Insurance Policies Net of Policy Loans		8,977		8,977
Forward Energy Contracts		8,030		8,030
Investments of Captive Insurance Company:				
Corporate Debt Securities	3,640			3,640
U.S. Government Debt Securities	2,104			2,104
Total Assets	$ 5,916	$ 27,755		$ 33,671
Liabilities:				
Forward Energy Contracts		$ 5,610		$ 5,610
Forward Foreign Currency Exchange Contracts	$ 6			6
Total Liabilities	$ 6	$ 5,610		$ 5,616
Net Assets	$ 5,910	$ 22,145		$ 28,055

<u>Inventories</u>

Inventories consist of the following:

(in thousands)	March 31, 2008	December 31, 2007
Finished Goods	$ 47,436	$ 38,952
Work in Process	5,293	5,218
Raw Material, Fuel and Supplies	62,527	53,044
	$ 115,256	$ 97,214

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Other Intangible Assets

The following table summarizes the components of the Company s intangible assets at March 31, 2008 and December 31, 2007:

(in thousands)	March 31, 2008 Gross Carrying Amount	March 31, 2008 Accumulated Amortization	March 31, 2008 Net Carrying Amount	December 31, 2007 Gross Carrying Amount	December 31, 2007 Accumulated Amortization	December 31, 2007 Net Carrying Amount
Amortized Intangible Assets:						
Covenants Not to Compete	$ 2,637	$ 2,168	$ 469	$ 2,637	$ 2,113	$ 524
Customer Relationships	10,855	1,566	9,289	10,879	1,469	9,410
Other Intangible Assets Including Contracts	2,785	1,831	954	2,785	1,775	1,010
Total	$ 16,277	$ 5,565	$ 10,712	$ 16,301	$ 5,357	$ 10,944
Nonamortized Intangible Assets:						
Brand/Trade Name	$ 9,505	$	$ 9,505	$ 9,512	$	$ 9,512

Intangible assets with finite lives are being amortized on a straight-line basis over average lives ranging from 3 to 25 years. The amortization expense for these intangible assets was $211,000 for the three months ended March 31, 2008 compared to $309,000 for the three months ended March 31, 2007. The estimated annual amortization expense for these intangible assets for the next five years is $889,000 for 2008, $795,000 for 2009, $623,000 for 2010, $516,000 for 2011 and $507,000 for 2012.

Comprehensive Income

(in thousands)	Three months ended March 31, 2008	Three months ended March 31, 2007
Net Income	$ 8,230	$ 10,408
Other Comprehensive (Loss) Income (net-of-tax)		
Foreign Currency Translation (Loss) Gain	(452)	104
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	43	44
Unrealized Gain (Loss) on Available-for-Sale Securities	59	(19)
Total Other Comprehensive (Loss) Income	(350)	129
Total Comprehensive Income	$ 7,880	$ 10,537

New Accounting Standards

SFAS No. 157, *Fair Value Measurements,* was issued by the Financial Accounting Standards Board (FASB) in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. Adoption of SFAS No. 157 will result in additional footnote disclosures related to the use of fair value measurements in the areas of investments, derivatives, asset retirement obligations, goodwill and asset impairment evaluations, financial instruments and acquisitions. The Company adopted SFAS No. 157 on January 1, 2008 and required disclosures are included in this report on Form 10-Q.

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SFAS No. 159, ***The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115,*** was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. As of March 31, 2008 the Company had not opted, nor does it currently plan to opt, to apply fair value accounting to any financial instruments or other items that it is not currently required to account for at fair value.

SFAS No. 141 (revised 2007), Businesses Combinations (SFAS No. 141(R)), was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations,* and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 January 1, 2009 for the Company. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term purchase method of accounting with acquisition method of accounting, SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141 s cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141 s guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

SFAS No. 161, ***Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133*** was issued by the FASB in March 2008. SFAS No. 161 requires enhanced disclosures about an entity s derivative and hedging activities to improve the transparency of financial reporting. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008 January 1, 2009 for the Company. Adoption of SFAS No. 161 will result in additional footnote disclosures related to the Company s use of derivative instruments but those additional disclosures will not be extensive because the derivative instruments currently held by the Company are not designated as hedging instruments under this statement.

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2. Segment Information

The Company s businesses have been classified into six segments based on products and services and reach customers in all 50 states and international markets. The six segments are: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations.

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

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

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

Manufacturing consists of businesses in the following manufacturing activities: production of waterfront equipment, wind towers, material and handling trays and horticultural containers, contract machining, and metal parts stamping and fabrication. These businesses have manufacturing facilities in Minnesota, North Dakota, South Carolina, Missouri, California, Florida, Oklahoma and Ontario, Canada and sell products primarily in the United States.

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

Food Ingredient Processing consists of IPH, which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. IPH produces dehydrated potato products that are sold in the United States, Canada and other countries.

Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries, fiber optic and electric distribution systems, wastewater and HVAC systems construction, transportation and energy services. These businesses operate primarily in the Central United States, except for the transportation company which operates in 48 states and 6 Canadian provinces.

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

The Company has a customer within the Manufacturing segment that accounted for approximately 13.6% of the Company s first quarter 2008 consolidated revenues. No other single external customer accounts for 10% or more of the Company s revenues. Substantially all of the Company s long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

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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 three month periods ended March 31, 2008 and 2007 and total assets by business segment as of March 31, 2008 and December 31, 2007 are presented in the following tables:

Operating Revenue

	Three months ended March 31,	
(in thousands)	2008	2007
Electric	$ 97,590	$ 89,980
Plastics	22,350	37,819
Manufacturing	97,595	86,225
Health Services	29,265	32,963
Food Ingredient Processing	15,898	19,495
Other Business Operations	38,110	35,146
Corporate Revenues and Intersegment Eliminations	(571)	(507)
Total	$ 300,237	$ 301,121

Interest Expense

	Three months ended March 31,	
(in thousands)	2008	2007
Electric	$ 2,981	$ 2,503
Plastics	141	185
Manufacturing	2,146	1,804
Health Services	179	205
Food Ingredient Processing	10	91
Other Business Operations	307	199
Corporate and Intersegment Eliminations	947	(119)
Total	$ 6,711	$ 4,868

Income Taxes

	Three months ended March 31,	
(in thousands)	2008	2007
Electric	$ 6,420	$ 3,226
Plastics	425	1,860
Manufacturing	(603)	1,545
Health Services	(415)	694
Food Ingredient Processing	600	239
Other Business Operations	(1,160)	59
Corporate	(2,149)	(1,852)
Total	$ 3,118	$ 5,771

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Earnings Available for Common Shares

(in thousands)	Three months ended March 31, 2008	2007
Electric	$ 12,566	$ 5,738
Plastics	620	2,828
Manufacturing	(616)	2,539
Health Services	(691)	948
Food Ingredient Processing	1,123	449
Other Business Operations	(1,765)	77
Corporate	(3,191)	(2,355)
Total	$ 8,046	$ 10,224

Total Assets

(in thousands)	March 31, 2008	December 31, 2007
Electric	$ 806,065	$ 813,565
Plastics	83,739	77,971
Manufacturing	282,068	274,780
Health Services	63,981	64,824
Food Ingredient Processing	94,654	91,966
Other Business Operations	76,262	72,258
Corporate	52,124	59,390
Total	$ 1,458,893	$ 1,454,754

The following table presents the percent of consolidated sales revenue by country:

	Three months ended March 31, 2008	2007
United States of America	96.1%	96.5%
Canada	1.2%	1.2%
All Other Countries (none greater than 1%)	2.7%	2.3%

3. Rate and Regulatory Matters

Minnesota

General Rate Case The electric utility filed a general rate case in Minnesota on October 1, 2007 requesting an interim rate increase of 5.4% effective November 30, 2007 and a final total rate increase of approximately 11%. However, the electric utility included a proposal to credit asset-based wholesale margins through the Fuel Clause Adjustment (FCA), so the final overall customer impact would be an increase of approximately 6.7%. The electric utility has since revised its proposal to credit asset-based wholesale margins through base rates, and made other adjustments to its request. The current request amounts to a 6.3% overall increase. The electric utility s interim rate request was approved and will remain in effect for all Minnesota customers until the Minnesota Public Utilities Commission (MPUC) makes a final determination on the final request, which is expected by August 1, 2008. The electric utility recorded $2.1 million in retail revenue in the first quarter of 2007 related to the 5.4% interim rate increase. If the MPUC approves final rates that are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt transmission lines. The MPUC is expected to decide if the lines are needed by early 2009. Portions of the lines would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. The MPUC would determine routes for the new lines in separate proceedings. After regulatory need is established and routing decisions are complete (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading the project, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. Otter Tail Power Company is directly involved in two of these three projects and serves as the lead utility in a fourth Group 1 project, the Bemidji-Grand Rapids 230-kv line. The electric utility filed a Certificate of Need for the fourth project on March 17, 2008. The MPUC is expected to decide if this line is needed in the third or fourth quarter of 2008. The electric utility expects to file a route permit for the Bemidji-Grand Rapids 230-kv line in early 2009. The electric utility s 2008 2012 capital budgets include $67 million for CapX 2020 expenditures.

Renewable Energy Standards, Conservation and Renewable Resource Riders In February 2007, the Minnesota legislature passed a renewable energy standard requiring the electric utility to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. The electric utility is ahead of the requirements schedule to be in compliance with the Minnesota renewable energy standard.

Under the Next Generation Energy Act passed by the Minnesota legislature in May 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover charges incurred to satisfy the requirements of the renewable energy standards. The MPUC is now authorized to approve a rate schedule rider to recover the costs of qualifying renewable energy projects to supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can now be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval in an integrated resource plan or certificate of need proceeding before the MPUC. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses. The electric utility has requested approval of a renewable resource rider that would allow recovery of eligible and prudently incurred costs for its qualifying renewable energy project investments. The proposed rider would cover the Minnesota jurisdictional portion of such eligible costs. The electric utility expects to receive MPUC approval of its proposed rider in 2008 and has recorded a regulatory asset of $865,000 related to the deferred recognition of the Minnesota portion of renewable resource costs incurred in the first quarter of 2008, pending approval and implementation of the proposed rider.

In addition, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new electric transmission facilities. The MPUC may approve a tariff to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a certificate of need proceeding or certified by the MPUC as a Minnesota priority transmission project or investment and expenditures made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility s retail customers. Such transmission cost recovery riders would allow a return on investments at the level approved in a utility s last general rate case. The electric utility is also preparing to file a proposed rider to recover its share of costs of transmission infrastructure upgrades projects. The electric utility currently expects to file its transmission cost recovery tariff and receive MPUC approval during 2008.

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North Dakota

The electric utility has requested approval of a renewable resource rider for its North Dakota jurisdictional portion of investments in renewable generation resources. The electric utility expects a decision on the rider in the second quarter of 2008.

North Dakota legislation also provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. The electric utility is not certain if it will file for recovery of such costs under the automatic adjustment mechanism or in its next general rate case filing.

Federal

Transmission Practices Audit The Division of Operation Audits of the Federal Energy Regulatory Commission (FERC) Office of Market Oversight and Investigations (OMOI) commenced an audit of the electric utility s transmission practices in 2005. The purpose of the audit is to determine whether and how the electric utility s transmission practices are in compliance with the FERC s applicable rules and regulations and tariff requirements and whether and how the implementation of the electric utility s waivers from the requirements of Order No. 889 and Order No. 2004 restricts access to transmission information that would benefit the electric utility s off-system sales. The electric utility has entered into a settlement agreement with FERC staff resolving all potential issues under the audit. The settlement agreement is subject to FERC approval. The Company does not expect the results of the audit to have a material impact on its consolidated financial statements.

Big Stone II Project

On June 30, 2005 the electric utility and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant s nominal generating capacity from 630 megawatts to between 500 and 580 megawatts. New procedural schedules have been established in the various project-related proceedings, which will take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

The electric utility and the coalition of six other electric providers filed an application for a Certificate of Need for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. Evidentiary hearings were conducted in December 2006 and all parties submitted legal briefs. The Administrative Law Judges (ALJs) on August 15, 2007 recommended approval of the Certificate of Need subject to potential conditions. The electric utility and project participants addressed the ALJs recommended potential conditions in an August 31, 2007 proposed settlement agreement with the MNDOC that was entered into the record of the Certificate of Need/Route Permit dockets. The MPUC had not acted on the applications or the proposed settlement agreement when Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. On October 19, 2007 the MPUC requested that the ALJs recommence proceedings in the matter and that the remaining project participants file testimony describing and supporting a revised Big Stone II project. The remaining five participants filed testimony on November 13, 2007. On December 3, 2007 the ALJs issued an order refining the scope of the additional proceedings. Evidentiary hearings were held on January 23-25, 2008. On May 9, 2008 the ALJs issued their report reversing their previous recommendation recommending that the MPUC deny the petition for a Certificate of Need and related route permits for the proposed transmission lines. The electric utility anticipates that the MPUC will consider these two issues in June 2008.

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The electric utility s integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. In addition to approval of the Certificate of Need/Route Permit applications for the transmission line project, approval of this IRP is pending with the MPUC.

A filing in North Dakota for an advanced determination of prudence of Big Stone II was made by the electric utility in November 2006. Evidentiary hearings were held in June 2007. The North Dakota Public Service Commission (NDPSC) decision was delayed because of the change in ownership of the project. The administrative law judge in the matter held supplemental hearings in April 2008. The Company expects the NDPSC to issue a decision in the second quarter of 2008.

As of March 31, 2008 the electric utility has capitalized $9.1 million in costs related to the planned construction of Big Stone II. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

4. Regulatory Assets and Liabilities

As a regulated entity the Company and the electric utility account for the financial effects of regulation in accordance with SFAS No. 71, *Accounting for the Effect of Certain Types of Regulation*. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation.

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

(in thousands)	March 31, 2008	December 31, 2007
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pension and Other Postretirement Benefits	$ 26,165	$ 26,933
Deferred Income Taxes	8,493	8,733
Accrued Cost-of-Energy Revenue	8,164	19,452
Reacquisition Premiums	3,646	3,745
Minnesota Renewable Resource Rider Recoverable Costs	865	
MISO Schedule 16 and 17 Deferred Administrative Costs MN	732	855
MISO Schedule 16 and 17 Deferred Administrative Costs ND	651	576
Accumulated ARO Accretion/Depreciation Adjustment	397	345
Plant Acquisition Costs	96	107
Deferred Conservation Program Costs	25	518
Deferred Marked-to-Market Losses		771
Total Regulatory Assets	$ 49,234	$ 62,035
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 58,126	$ 57,787
Deferred Income Taxes	4,716	4,502
Gain on Sale of Division Office Building	144	145
Deferred Marked-to-Market Gains		271
Total Regulatory Liabilities	$ 62,986	$ 62,705
Net Regulatory Liability Position	$ 13,752	$ 670

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The regulatory asset related to the unrecognized transition obligation on postretirement medical benefits and prior service costs and actuarial losses on pension and other postretirement benefits represents benefit costs that will be subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs were required to be recognized as components of Accumulated Other Comprehensive Income in equity under SFAS No. 158, *Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans,* adopted in December 2006, but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates. The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes*. Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next nine months. Reacquisition Premiums included in Unamortized Debt Expense are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 24.5 years. The deferred Minnesota Renewable Resource Rider Recoverable Costs are expected to be recovered from July 2008 through December 2009, provided the proposed rider is approved by the MPUC prior to July 2008. MISO Schedule 16 and 17 Deferred Administrative Costs MN were excluded from recovery through the FCA in Minnesota in a December 2006 order issued by the MPUC. The MPUC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility s Minnesota general rate case filed on October 1, 2007. The electric utility began amortizing the Minnesota portion of MISO schedule 16 and 17 deferred costs over a 36-month amortization period with the inception of interim rates in December 2007. MISO Schedule 16 and 17 Deferred Administrative Costs ND were excluded from recovery through the FCA in North Dakota in an August 2007 order issued by the NDPSC. The NDPSC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility s next general rate case in North Dakota scheduled to be filed in November or December of 2008. Plant Acquisition Costs will be amortized over the next 2.2 years. The Accumulated Reserve for Estimated Removal Costs is reduced for actual removal costs incurred. Deferred Conservation Program Costs represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. All Deferred Marked-to-Market Losses and Gains were related to forward purchases of energy scheduled for delivery in January and February of 2008. The remaining regulatory assets and liabilities are being recovered from, or will be paid to, electric customers over the next 30 years.

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

5. Forward Contracts Classified as Derivatives

As of March 31, 2008 the electric utility had recognized, on a pretax basis, $2,420,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. The market prices used to value the electric utility s forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility s power services personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in SFAS No. 157.

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

(in thousands)	March 31, 2008
Current Asset Marked-to-Market Gain	$ 8,030
Current Liability Marked-to-Market Loss	(5,610)
Net Fair Value of Marked-to-Market Energy Contracts	$ 2,420

(in thousands)	Year-to-Date March 31, 2008
Fair Value at Beginning of Year	$ 632
Amount Realized on Contracts Entered into in 2007 and Settled in 2008	(204)
Changes in Fair Value of Contracts Entered into in 2007	369
Net Fair Value of Contracts Entered into in 2007 at End of Period	797
Changes in Fair Value of Contracts Entered into in 2008	1,623
Net Fair Value End of Period	$ 2,420

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH s Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars on March 20, 2008 to cover approximately 50% of its monthly expenditures for the last nine months of 2008. Each contract is for the exchange of $400,000 USD for the amount of Canadian dollars stated in each contract, for a total exchange of $3,600,000 USD for $3,695,280 CAD. Each of these contracts can be settled incrementally during the month the contract is scheduled for settlement, but for practical reasons and to reduce settlement fees each contract will most likely be settled in one or two exchanges.

These open contracts are derivatives subject to mark-to-market accounting. IPH does not enter into these contracts for speculative purposes or with the intent of early settlement, but for the purpose of locking in acceptable exchange rates and hedging its exposure to future fluctuations in exchange rates with the intent of settling these contracts during their stated settlement periods and using the proceeds to pay its Canadian liabilities when they come due. These contracts will not qualify for hedge accounting treatment because the timing of their settlements will not coincide with the payment of specific bills or existing contractual obligations.

These foreign currency exchange forward contracts were valued and marked to market on March 31, 2008 based on quoted exchange values of similar contracts that could be purchased on March 31, 2008. Based on those values, IPH s Canadian subsidiary recorded a derivative liability and mark-to-market loss of $6,000 as of, and for the three month period ended, March 31, 2008. The fair value measurements of these forward energy contracts fall into level 1 of the fair value hierarchy set forth in SFAS No. 157.

6. Common Shares and Earnings Per Share

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

Common Shares Outstanding, December 31, 2007	29,849,789
Issuances:	
Stock Options Exercised	27,913
Executive Officer Stock Performance Awards	62,625
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(20,207)
Common Shares Outstanding, March 31, 2008	29,920,120

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

For the three month periods ended March 31, 2008 and 2007 there were no outstanding stock options which had exercise prices greater than the average market price. Therefore, outstanding options were included in the calculation of diluted earnings per share for the respective periods.

7. Share-Based Payments

The Company has six share-based payment programs. No new stock awards were granted under these programs in the first quarter of 2008. As of March 31, 2008 the remaining unrecognized compensation expense related to stock-based compensation was approximately $3.9 million (before income taxes) which will be amortized over a weighted-average period of 2.1 years.

Amounts of compensation expense recognized under the Company s six stock-based payment programs for the three months ended March 31, 2008 and 2007 are presented in the table below:

	Three months ended March 31,	
(in thousands)	2008	2007
1999 Employee Stock Purchase Plan	$ 70	$ 64
Stock Options Granted Under the 1999 Stock Incentive Plan		68
Restricted Stock Granted to Directors	108	151
Restricted Stock Granted to Employees	118	166
Restricted Stock Units Granted to Employees	94	69
Stock Performance Awards Granted to Executive Officers	340	221
Totals	$ 730	$ 739

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9. Commitments and Contingencies

In March 2008, DMI Industries, Inc., the Company s wind tower manufacturer, entered into a three year $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to a third party financial institution on a revolving basis. As of March 31, 2008, DMI had sold $22.4 million of accounts receivable to the third party financial institution to mitigate accounts receivable concentration risk. Any obligations of DMI to the third party financial institution under the receivables purchase agreement is guaranteed by Varistar Corporation, DMI s parent company.

In compliance with SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows.

11. Class B Stock Options of Subsidiary

As of March 31, 2008 there were 933 options for the purchase of IPH Class B common shares outstanding with a combined exercise price of $691,000, of which 753 options were in-the-money with a combined exercise price of $316,000.

12. Pension Plan and Other Postretirement Benefits

Pension Plan Components of net periodic pension benefit cost of the Company s noncontributory funded pension plan are as follows:

	Three months ended March 31,	
(in thousands)	2008	2007
Service Cost Benefit Earned During the Period	$ 1,275	$ 1,263
Interest Cost on Projected Benefit Obligation	2,800	2,733
Expected Return on Assets	(3,550)	(3,223)
Amortization of Prior-Service Cost	175	185
Amortization of Net Actuarial Loss	125	309
Net Periodic Pension Cost	$ 825	$ 1,267

The Company did not make a contribution to its pension plan in the three months ended March 31, 2008 and is not required to make a contribution in 2008.

Executive Survivor and Supplemental Retirement Plan Components of net periodic pension benefit cost of the Company s unfunded, nonqualified benefit plan for executive officers and certain key management employees are as follows:

	Three months ended March 31,	
(in thousands)	2008	2007
Service Cost Benefit Earned During the Period	$ 173	$ 156
Interest Cost on Projected Benefit Obligation	384	363
Amortization of Prior-Service Cost	16	17
Amortization of Net Actuarial Loss	120	135
Net Periodic Pension Cost	$ 693	$ 671

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Postretirement Benefits Components of net periodic postretirement benefit cost for health insurance and life insurance benefits for retired electric utility and corporate employees are as follows:

	Three months ended March 31,	
(in thousands)	2008	2007
Service Cost Benefit Earned During the Period	$ 300	$ 315
Interest Cost on Projected Benefit Obligation	725	698
Amortization of Transition Obligation	187	187
Amortization of Prior-Service Cost	50	(51)
Amortization of Net Actuarial Loss	125	129
Effect of Medicare Part D Expected Subsidy	(400)	(410)
Net Periodic Postretirement Benefit Cost	$ 987	$ 868

19. Subsequent Events

On April 14, 2008 the Company s Board of Directors granted 26,050 restricted stock units to key employees under the 1999 Stock Incentive Plan, as amended (Incentive Plan) payable in common shares on April 8, 2012, the date the units vest. The grant date fair value of each restricted stock unit was $30.81 per share. Also on April 14, 2008 the Company s Board of Directors approved the award of 600 restricted stock units to be granted effective July 1, 2008 for another key employee under the Incentive Plan payable in common shares on July 1, 2011, the date the units vest. The grant date fair value of these restricted stock units will be determined under a Monte Carlo valuation method based on the market value of the Company s common stock on July 1, 2008.

On April 14, 2008 the Company s Board of Directors granted 20,000 shares of restricted stock to the Company s nonemployee directors, 17,600 shares of restricted stock to the Company s executive officers and 1,771 shares of restricted stock to a key employee under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2009 through 2012 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $35.345 per share, the average market price on the date of grant.

On April 14, 2008 the Company s Board of Directors granted performance share awards to the Company s executive officers under the Incentive Plan. Under these awards, the Company s executive officers could earn up to an aggregate of 114,800 common shares based on the Company s total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance period of January 1, 2008 through December 31, 2010. The aggregate target share award is 57,400 shares. Actual payment may range from zero to 200% of the target amount. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance period. The grant date fair value of the common shares projected to be awarded was $37.59 per share, as determined under a Monte Carlo valuation method.

On April 30, 2008 Otter Tail Power Company announced plans to invest $121 million related to the construction of 48 megawatts of wind energy generation at the proposed Ashtabula Wind Center site in Barnes County, North Dakota. Contractual commitments related to this project have increased the electric utility s commitments under contracts in connection with construction programs reported in note 9 of Notes to Consolidated Financial Statements in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2007 by $80.3 million in 2008.

On May 1, 2008 BTD Manufacturing, Inc. (BTD) acquired the assets of Miller Welding & Iron Works (Miller Welding) of Washington, Illinois for $40.0 million in cash. Miller Welding, a custom job shop fabricator and finisher recorded $26 million in revenue in 2007. Miller Welding manufactures and fabricates parts for off-road

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equipment, mining machinery, oil fields and offshore oil rigs, wind industry components, broadcast antennae and farm equipment, and serves several major equipment manufacturers in the Peoria, Illinois area and nationwide, including Caterpillar, Komatsu and Gardner Denver. This acquisition will provide opportunities for growth in new and existing markets for both BTD and Miller Welding, and complementing production capabilities will expand the scope and capacity of services offered by both companies.

On May 9, 2008 the ALJs considering whether to recommend a Certificate of Need and route permit for the proposed transmission lines related to Big Stone II recommended that the MPUC deny the petition for a Certificate of Need and associated route permits. The electric utility anticipates that the MPUC will consider these two issues in June 2008.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

RESULTS OF OPERATIONS

Comparison of the Three Months Ended March 31, 2008 and 2007

Consolidated operating revenues were $300.2 million for the three months ended March 31, 2008 compared with $301.1 million for the three months ended March 31, 2007. Operating income was $17.1 million for the three months ended March 31, 2008 compared with $20.8 million for the three months ended March 31, 2007. The Company recorded diluted earnings per share of $0.27 for the three months ended March 31, 2008 compared to $0.34 for the three months ended March 31, 2007.

Following is a more detailed analysis of our operating results by business segment for the quarters ended March 31, 2008 and 2007, followed by our outlook for the remainder of 2008 and a discussion of changes in our consolidated financial position during the quarter ended March 31, 2008.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the three month periods ended March 31, 2008 and 2007 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

(in thousands)	March 31, 2008	March 31, 2007
Operating Revenues:		
Electric	$ 85	$ 127
Nonelectric	486	380
Cost of Goods Sold	466	369
Other Nonelectric Expenses	105	138

Electric

(in thousands)	Three months ended March 31, 2008	2007	Change	% Change
Retail Sales Revenues	$ 87,300	$ 81,176	$ 6,124	7.5
Wholesale Revenues	3,584	4,234	(650)	(15.4)
Net Marked-to-Market Gain (Loss)	2,250	(31)	2,281	
Other Revenues	4,456	4,601	(145)	(3.2)
Total Operating Revenues	$ 97,590	$ 89,980	$ 7,610	8.5
Production Fuel	19,904	16,425	3,479	21.2
Purchased Power System Use	18,986	26,011	(7,025)	(27.0)
Other Operation and Maintenance Expenses	26,743	26,875	(132)	(0.5)
Depreciation and Amortization	7,708	6,670	1,038	15.6
Property Taxes	2,624	2,526	98	3.9
Operating Income	$ 21,625	$ 11,473	$ 10,152	88.5

The primary reason for the increase in retail revenues was a 7.9% increase in retail kilowatt-hour (kwh) sales resulting from colder weather. Heating degree days increased 8.4% in the first quarter of 2008 compared with the first quarter of 2007. A 5.4% interim rate increase in Minnesota retail rates in connection with the electric utility s application for a general rate increase contributed approximately $2.1 million to the increase in retail revenues. Retail revenues related to the recovery of fuel and purchased power costs were down $3.7 million and fuel and purchased power costs related to retail use were down $3.2 million despite the increase in retail kwh sales. This was a result of generating more electricity from company-owned generators and purchasing less electricity from others to serve retail load. The average cost per kwh of purchased power for retail use was more than four times as much as the average fuel cost per kwh from company-owned generators in the first quarters of 2008 and 2007.

Wholesale electric revenues from sales from company-owned generation were $4.1 million for the quarter ended March 31, 2008 compared with $6.0 million for the quarter ended March 31, 2007 as a result of higher retail loads during the quarter ended March 31, 2008 due to colder weather resulting in lower volumes of excess generation available for sale into the market. Amounts sold were also sold at lower prices during the quarter ended March 31, 2008. Plant availability, demand, load distribution and economic dispatch across the entire Midwest Independent Transmission System Operator (MISO) region are all factors that drive wholesale prices of electricity. Net gains from energy trading activities, including net mark-to-market gains on forward energy contracts, were $1.7 million for the quarter ended March 31, 2008 compared with net losses of $1.8 million for the quarter ended March 31, 2007. Fuel costs related to wholesale sales decreased $0.4 million.

The increase in fuel costs reflects a 15.3% increase in kwhs generated combined with a 5.1% increase in the cost of fuel per kwh generated. Generation for retail sales increased 20.1% while generation used for wholesale electric sales decreased 11.7% between the quarters. The electric utility was able to increase kwh output at its Big Stone Plant by 32.7% in the first quarter of 2008 compared with the first quarter of 2007 due, in part, to the replacement of its advanced hybrid particulate collector with a new flue-gas treatment system during the fourth quarter 2007 maintenance shutdown. The increase in fuel costs per kwh is directly related to higher diesel fuel prices which result in increased costs to operate coal mines and to transport coal by rail. Approximately 90% of the fuel cost increases associated with generation to serve retail electric customers is subject to recovery through the FCA component of retail rates. The electric utility s 27 new wind turbines at the Langdon Wind Energy Center provided 2.3% of total kwh generation in the first quarter of 2008.

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The decrease in purchased power system use is due to a 31.8% reduction in mwhs purchased partially offset by a 7.0% increase in the cost per mwh purchased. The decrease in mwh purchases for system use was directly related to the increase in mwhs generated at company-owned plants. The increase in the cost per mwh of purchased power reflects a general increase in fuel and purchased power costs across the Mid-Continent Area Power Pool region as a result of higher demand due to colder weather in the first quarter of 2008 compared with the first quarter of 2007. Electric operating and maintenance expenses were essentially unchanged. Depreciation expenses and property taxes increased as a result of recent capital additions, including 27 new wind turbines at the Langdon Wind Energy Center.

Plastics

	Three months ended March 31,			%
(in thousands)	2008	2007	Change	Change
Operating Revenues	$ 22,350	$ 37,819	$ (15,469)	(40.9)
Cost of Goods Sold	18,936	30,648	(11,712)	(38.2)
Operating Expenses	1,438	1,539	(101)	(6.6)
Depreciation and Amortization	795	765	30	3.9
Operating Income	$ 1,181	$ 4,867	$ (3,686)	(75.7)

Operating revenues for the plastics segment decreased mainly as result of a 43.9% decrease in pounds of pipe sold, partially offset by a 5.4% increase in the price per pound of pipe sold between the quarters. The decrease in pounds of pipe sold was due to softening in the construction markets served by this segment, which was expected. The decrease in cost of goods sold was directly related to the decrease in pounds of pipe sold. However, the cost per pound of pipe sold increased 10.1% due to higher resin prices, resulting in a 15.0% decline in gross margins per pound of pipe sold.

Manufacturing

	Three months ended March 31,			%
(in thousands)	2008	2007	Change	Change
Operating Revenues	$ 97,595	$ 86,225	$ 11,370	13.2
Cost of Goods Sold	82,848	69,246	13,602	19.6
Operating Expenses	10,323	7,931	2,392	30.2
Depreciation and Amortization	3,749	3,110	639	20.5
Operating Income	$ 675	$ 5,938	$ (5,263)	(88.6)

The increase in revenues in our manufacturing segment relates to the following:

Revenues at DMI Industries, Inc. (DMI) increased $6.7 million as a result of increases in production and sales activity, including initial operations at its new plant in Oklahoma.

Revenues at BTD Manufacturing, Inc. (BTD) increased $3.0 million due to increased business with existing customers as well as new business related to the acquisition of Pro Engineering, LLC in May 2007.

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Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $2.0 million as a result of increased sales of horticultural products.

Revenues at ShoreMaster, Inc. (ShoreMaster) decreased $0.3 million between the quarters. ShoreMaster experienced revenue increases at all of its production facilities except its plant in Camdenton, Missouri, which recorded a $2.7 million decrease in sales revenue as a result of reduced volumes of commercial sales activity in the region.

The increase in cost of goods sold in our manufacturing segment relates to the following:

DMI s cost of goods sold increased $9.2 million as a result of increases in production and sales activity, including initial operations at its new plant in Oklahoma. Included in cost of goods sold for the quarter ended March 31, 2008 are costs of $0.8 million associated with the start up of DMI s new plant in Oklahoma and $3.2 million in additional labor and material costs on a production contract at the Fort Erie plant. These items contributed to a $2.5 million reduction in DMI s gross profits between the quarters.

Cost of goods sold at BTD increased $2.5 million in relationship to BTD s increased sales, mainly in the categories of material, labor and subcontractor costs.

Cost of goods sold at T.O. Plastics increased $1.4 million, mainly due to increased sales of horticultural products.

Cost of goods sold at ShoreMaster increased $0.5 million. Cost of goods sold at all of ShoreMaster s production facilities, except its plant in Camdenton, Missouri, increased commensurate with increases in sales revenues from those facilities resulting in increased profit margins at those facilities. However, gross profits declined at Camdenton relative to the decrease in sales volume.

The increase in operating expenses in our manufacturing segment is due to the following:

Operating expenses at DMI increased $0.8 million, mainly related to operation of its new plant in Oklahoma, which began construction in the third quarter of 2007 and went into operation in January 2008.

BTD s operating expenses increased $0.5 million as a result of increases in labor and benefit costs and the May 2007 acquisition of Pro Engineering.

ShoreMaster s operating expenses increased $1.1 million as a result of increases of $0.3 million in sales and marketing expenses, $0.3 million in salary and benefit expenses, $0.2 million in contracted services related to software implementation and $0.1 million in bad debt expense. Operating expenses at ShoreMaster s Camdenton, Missouri plant were flat between the quarters. The increases in operating expenses at ShoreMaster s other facilities completely offset the increases in gross profits from those facilities resulting in no increase in operating income from those facilities.

T.O. Plastics operating expenses were flat between the quarters.

Depreciation expense increased as a result of capital additions at DMI and T.O. Plastics.

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Health Services

(in thousands)	Three months ended March 31, 2008	2007	Change	% Change
Operating Revenues	$ 29,265	$ 32,963	$ (3,698)	(11.2)
Cost of Goods Sold	23,291	24,383	(1,092)	(4.5)
Operating Expenses	5,925	5,806	119	2.0
Depreciation and Amortization	982	962	20	2.1
Operating (Loss) Income	$ (933)	$ 1,812	$ (2,745)	(151.5)

In the health services segment, revenues from scanning and other related services were down $2.1 million and revenues from equipment sales and servicing decreased $1.6 million for the three months ended March 31, 2008 compared with the three months ended March 31, 2007. The decrease in cost of goods sold was directly related to the decrease in equipment sales revenue. The imaging side of the business continues to be affected by less than optimal utilization of certain imaging assets.

Food Ingredient Processing

(in thousands)	Three months ended March 31, 2008	2007	Change	% Change
Operating Revenues	$ 15,898	$ 19,495	$ (3,597)	(18.5)
Cost of Goods Sold	12,319	16,993	(4,674)	(27.5)
Operating Expenses	813	752	61	8.1
Depreciation and Amortization	1,073	969	104	10.7
Operating Income	$ 1,693	$ 781	$ 912	116.8

The decrease in revenues in the food ingredient processing segment is due to a 25.3% decrease in pounds of product sold, partially offset by a 9.2% increase in the price per pound of product sold. Cost of goods sold decreased as a result of the decrease in sales and a 2.9% decrease in the cost per pound of product sold. The selling off of higher-cost inventory items in the first quarter of 2007 combined with higher average selling prices and lower average costs for the mix of products sold in the first quarter of 2008 contributed to the decrease in pounds of product sold but resulted in an increase in profit margins between the quarters. The increases in operating and depreciation and amortization expenses between the quarters are mainly related to foreign currency translations and the change in the value of the Canadian dollar relative to the U.S. dollar from the first quarter of 2007 to the first quarter of 2008.

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Other Business Operations

(in thousands)	Three months ended March 31, 2008	2007	Change	% Change
Operating Revenues	$ 38,110	$ 35,146	$ 2,964	8.4
Cost of Goods Sold	28,295	23,758	4,537	19.1
Operating Expenses	12,013	10,613	1,400	13.2
Depreciation and Amortization	461	452	9	2.0
Operating (Loss) Income	$ (2,659)	$ 323	$ (2,982)	

The increase in revenues in the other business operations segment relates to the following:

Revenues at Foley Company increased $4.1 million due to an increase in volume of jobs in progress.

Revenues at Midwest Construction Services, Inc. (MCS) decreased $1.6 million as a result of a decrease in jobs in progress between the quarters due to unfavorable weather conditions in the first quarter of 2008 compared with the first quarter of 2007 and a decline in bid activity between the periods.

Revenues at E.W. Wylie Corporation (Wylie) increased $0.5 million mainly as a result of the impact of increased fuel costs on shipping rates. Miles driven by company-owned trucks increased 23.9% while miles driven by owner-operated trucks decreased 45.6%. Combined miles driven by company-owned and owner-operated trucks decreased 3.2% between the quarters.

The increase in cost of goods sold in the other business operations segment relates to the following:

Foley Company s cost of goods sold increased $3.9 million, including increases of $3.5 million in subcontractor and material costs and $0.4 million in labor and benefit costs, as a result of increased construction activity and jobs in progress.

Cost of goods sold at MCS increased $0.6 million between the quarters due to increases in indirect labor, insurance and equipment operating costs on higher-cost contracts initiated in 2007, resulting in lower than expected margins on those contracts in the first quarter of 2008.

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

Wylie s operating expenses increased $0.9 million between the quarters. Fuel costs increased $1.5 million as a result of higher diesel fuel prices and an increase in miles driven by company-owned trucks. Labor costs increased by $0.2 million and equipment rental costs increased by $0.2 million due to the addition of heavy-haul services in the fourth quarter of 2007, which also contributed to the increase in miles driven by company-owned trucks. Subcontractor expenses decreased $1.0 million as a result of the decrease in miles driven by owner-operated trucks.

Operating expenses at Otter Tail Energy Services Company increased $0.2 million between the quarters related to the investigation and development of renewable energy wind-generation projects.

Foley Company s operating expenses increased $0.1 million between the quarters.

MCS s operating expenses increased $0.1 million between the quarters.

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Corporate

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

	Three months ended March 31,			%
(in thousands)	2008	2007	Change	Change
Operating Expenses	$4,340	$4,255	$ 85	2.0
Depreciation and Amortization	145	165	(20)	(12.1)

Interest Charges

Interest charges increased $1.8 million in the first three months of 2008 compared with the first three months of 2007 as a result of increases in both average long-term debt outstanding and average short-term debt outstanding between the quarters.

Other Income

The $0.7 million increase in other income was mainly due to an increase in the allowance for equity funds used in construction at the electric utility in the first three months of 2008 compared with the first three months of 2007. The electric utility recorded no allowance for equity funds used in construction in the first quarter of 2007 because its average balance of construction work in progress was less than average short-term borrowings during the quarter.

Income Taxes

The $2.7 million (46.0%) decrease in income taxes between the quarters is primarily the result of a $4.8 million (29.9%) decrease in income before income taxes for the three months ended March 31, 2008 compared with the three months ended March 31, 2007. The effective tax rate for the three months ended March 31, 2008 was 27.5% compared to 35.7% for the three months ended March 31, 2007. Federal production tax credits of $0.5 million and North Dakota wind tax credits of $0.1 million recorded in the first quarter of 2008 related to the electric utility s new wind turbines contributed to the reduction in taxes and the reduction in the effective tax rate between the quarters.

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2008 EXPECTATIONS

The statements in this section are based on our current outlook for 2008 and are subject to risks and uncertainties described under Forward Looking Information Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995.

We are revising our 2008 earnings guidance to be in a range from $1.75 to $2.00 of diluted earnings per share from our previously announced range of $1.85 to $2.10. Contributing to the earnings guidance for 2008 are the following items:

We expect increased levels of net income from our electric segment in 2008. The increase is attributable to an increase in revenues from a pending rate case in Minnesota and rate riders for wind energy and transmission investments in North Dakota and Minnesota. The interim rates are currently in effect during the pending Minnesota rate case. If final rates are lower than interim rates, a refund will be due. If final rates are higher, the higher rates will be prospective only. The increase also reflects having lower-cost generation available for the year, as no major plant shutdowns are planned for Big Stone Plant or Coyote Station in 2008.

We expect our plastics segment s 2008 performance to be below normal levels as this segment continues to be impacted by sluggish housing and construction markets. Announced capacity expansions are not expected to have a material impact on 2008.

We expect increased capacity and productivity related to recent expansions and acquisitions as well as the start-up of DMI s wind tower manufacturing plant in Oklahoma in 2008 to result in increased levels of net income in our manufacturing segment in 2008. Offsetting this overall segment growth are the effects of a softening economy and the impact it is having on ShoreMaster. Backlog in place at March 31, 2008 in the manufacturing segment to support revenues for the remainder of 2008 is approximately $280 million. This compares with $187 million as of March 31, 2007. DMI Industries accounts for a substantial portion of the 2008 backlog.

We expect improvement in net income in our health services segment in 2008 as it focuses on improving its mix of imaging assets and asset utilization rates.

We expect our food ingredient processing business to have increased net income due to higher operating margins in 2008. This business has backlog in place as of March 31, 2008 of 89.1 million pounds for the remainder of 2008 compared with 74.0 million pounds as of March 31, 2007.

We expect our other business operations segment to have higher earnings in 2008 compared with 2007. Backlog in place for the construction businesses at the end of the first quarter of 2008 was approximately $83 million for the remainder of 2008 compared with $87 million at the same time in 2007.

We expect corporate general and administrative costs to increase in 2008.

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FINANCIAL POSITION

For the period 2008 through 2012, we estimate funds internally generated net of forecasted dividend payments will be sufficient to repay a portion of currently outstanding short-term debt or to finance a portion of current capital expenditures. 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 our companies could have an effect on funds internally generated. Additional equity or debt financing will be required in the period 2008 through 2012 to finance the expansion plans of our electric segment, including $336 million for the construction of the proposed new Big Stone II generating station at the Big Stone Plant site, the announced $121 million planned investment in 48 megawatts of new wind energy generation and other proposed wind generation projects, to reduce borrowings under our lines of credit, including borrowings used to finance DMI s recent plant additions and BTD s acquisition of Miller Welding & Iron Works (Miller Welding), to refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

On April 30, 2008 Otter Tail Power Company announced plans to invest $121 million related to the construction of 48 megawatts (MW) of wind energy generation at the proposed Ashtabula Wind Center site in Barnes County, North Dakota, with an expected completion date in late 2008. Otter Tail Power Company s participation in the proposed project includes the ownership of 32 wind turbines rated at 1.5 MW each. Current contracts related to construction of the 32 wind towers and turbines to be owned by Otter Tail Power Company will increase our 2008 purchase obligations by $80.3 million.

We have the ability to issue up to $256 million of common stock, preferred stock, debt and certain other securities from time to time under our universal shelf registration statement filed with the Securities and Exchange Commission.

Our wholly owned subsidiary, Varistar Corporation (Varistar), has a $200 million credit agreement (the Varistar Credit Agreement) with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. The Varistar Credit Agreement is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Varistar Credit Agreement expires on October 2, 2010. Borrowings under the line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on Varistar s adjusted cash flow leverage ratio (as defined in the Varistar Credit Agreement). The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Varistar s obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Outstanding letters of credit issued by Varistar can reduce the amount available for borrowing under the line by up to $30 million. As of March 31, 2008, $110.0 million of the $200 million line of credit was in use and $14.9 million was restricted from use to cover outstanding letters of credit.

Otter Tail Corporation, dba Otter Tail Power Company, has a credit agreement with U.S. Bank National Association (the Electric Utility Credit Agreement) providing for a separate $75 million line of credit. This line of credit is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of our senior unsecured debt. The Electric Utility Credit

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Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement is subject to renewal on September 1, 2008. As of March 31, 2008, $12.2 million was borrowed under the Electric Utility Credit Agreement.

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

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

The Electric Utility Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement and the Lombard US Equipment Finance note contain covenants by us not to permit our debt-to-total capitalization ratio to exceed 60% or permit our interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, our interest coverage ratio) to be less than 1.5 to 1. The note purchase agreements further restrict us from allowing our priority debt to exceed 20% of total capitalization. Financial covenants in the Varistar Credit Agreement require Varistar to maintain a fixed charge coverage ratio of not less than 1.25 to 1 and to not permit its cash flow leverage ratio to exceed 3.0 to 1. We and Varistar were in compliance with all of the covenants under our financing agreements as of March 31, 2008.

Our obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of our subsidiaries. Varistar s obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Our Grant County and Mercer County Pollution Control Refunding Revenue Bonds require that we 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 our senior unsecured debt is downgraded to Baa2 or below (Moody s) or BBB or below (Standard & Poor s).

Our securities ratings at March 31, 2008 were:

	Moody s Investors Service	Standard & Poor s
Senior Unsecured Debt	A3	BBB+
Preferred Stock	Baa2	BBB-
Outlook	Negative	Negative

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

In March 2008, DMI entered into a three year $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to a third party financial institution on a revolving basis. As of March 31, 2008, DMI had sold $22.4 million of accounts receivable to the third party financial institution to mitigate accounts receivable concentration risk. Any obligations of DMI to the third party financial institution under the receivables purchase agreement is guaranteed by Varistar, DMI s parent company.

Cash provided by operating activities was $7.4 million for the three months ended March 31, 2008 compared with cash used in operating activities of $15.6 million for the three months ended March 31, 2007. The $23.0 million increase in cash from operating activities reflects a $22.9 million decrease in cash used for working capital items from $41.4 million in the first quarter of 2007 to $18.5 million in the first quarter of 2008. Cash flows from changes in receivables increased by $23.9 million. This was mostly the result of the receipt of $19.8 million in proceeds from the sale of receivables in March 2008 under the receivables purchase agreement entered into in March 2008.

Major uses of funds for working capital items in the first three months of 2008 were an increase in inventories of $18.2 million, a decrease in payables and current liabilities of $5.5 million and an increase in other current assets of $3.5 million, offset by an decrease in receivables of $8.4 million and an increase in interest and income taxes payable of $0.4 million. The $18.2 million increase in inventories includes increases of: (1) $11.5 million at the plastic pipe companies mainly related to a seasonal build up of finished goods inventory, (2) $4.4 million at ShoreMaster related to raw material purchased in advance of the spring and summer sales season and for a major contract at ShoreMaster s Florida production plant, and (3) $3.3 million at IPH, mainly in finished goods, as a result of decreased sales in the first quarter of 2008 combined with steady production. The $5.5 million decrease in payables and other current liabilities is mainly related to decreases in accrued bonuses across all companies as a result of the payment of 2007 bonuses in the first quarter of 2008. The $3.5 million increase in other current assets includes: (1) a $6.7 million increase in prepaid insurance across all companies related to the payment of 2008 annual premiums, (2) a $4.9 million increase in costs in excess of billings, mainly at DMI, as a result of increased production activity, and (3) a $1.1 million in income taxes receivable, offset by (4) a $9.1 million decrease in accrued utility revenues related to a decrease in unbilled revenue related to milder weather in March 2008 than December 2007, a reduction in accrued fuel clause adjustment revenues related to increased availability of Big Stone Plant in the first quarter of 2008 and a 1¢/kwh shift in recovery of fuel costs in Minnesota from the FCA to interim rates. The $8.4 million decrease in accounts receivable is due to: (1) a $14.9 million decrease at DMI related to its sale of receivables to a third-party financial institution in March 2008, (2) a $5.4 million decrease at the construction companies related to a seasonal reduction in construction activity in the first quarter of 2008, and (3) a $1.8 million reduction in receivables in the health services segment related to a decline in equipment sales and rentals, offset by (4) a $13.8 million increase in retail trade receivables at the electric utility mainly related to an increase in billed FCA revenues.

Net cash used in investing activities was $56.7 million for the three months ended March 31, 2008 compared with $25.5 million for the three months ended March 31, 2007. Cash used for capital expenditures increased by $33.8 million between the quarters. Cash used for capital expenditures at the electric utility increased by $24.6 million, mainly due to the construction of wind turbines related assets at the Langdon Wind Energy Center. Cash used for capital expenditures at DMI increased $4.5 million related to plant construction costs in Oklahoma and plant expansion costs in Fort Erie. Wylie s capital expenditures increased $1.5 million and ShoreMaster s capital expenditures increased $1.2 million between the quarters. The Company made no acquisitions in the first quarter of 2008 compared with $2.0 million for ShoreMaster s acquisition of the Aviva Sports product line in the first quarter of 2007. The net increase in proceeds from the disposal of noncurrent assets and cash used for other investments of $1.5 million in the first quarter of 2007 was mainly due to the sales of short-term investments and the reinvestment of proceeds from those sales by our captive insurance company.

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Net cash provided by financing activities was $18.7 million for the three months ended March 31, 2008 compared $34.1 million for the three months ended March 31, 2007. Proceeds from short-term borrowings were $27.2 million in the first quarter of 2008 compared with proceeds from short-term borrowings and checks written in excess of cash of $40.8 million in the first quarter of 2007. Proceeds from the issuance of common stock were $0.5 million in the first quarter of 2008 compared with $2.8 million in the first quarter of 2007. During the first quarter of 2008 the Company issued 27,913 common shares for stock options exercised compared with 127,931 common shares issued for stock options exercised in the first quarter of 2007. The Company paid $9.1 million in dividends on common and preferred shares in the first quarter of 2008 compared with $8.8 million in the first quarter of 2007. The increase in dividend payments is due to a half-cent per share increase in common dividends paid and a 1.2% increase in common shares outstanding between the quarters

Due to the approval of additional capital expenditures in the first quarter of 2008, we have revised our estimated capital expenditures by segment for 2008 and the years 2008 through 2012 from those presented on page 26 of our 2007 Annual Report to Shareholders as presented in the following table:

(in millions)	2008	2008-2012
Electric	$ 215	$ 880
Plastics	13	21
Manufacturing	18	80
Health Services	2	11
Food Ingredient Processing	4	18
Other Business Operations	4	9
Corporate		1
Total	$ 256	$ 1,020

Current estimated capital expenditures for our share of Big Stone II are $336 million.

Our purchase obligations in our contractual obligations table reported under the caption Capital Requirements on page 26 of our 2007 Annual Report to Shareholders have increased by $80.3 million for 2008 related to the announced plan to invest in the construction of 48 MW of wind energy generation at the proposed Ashtabula Wind Center site in Barnes County, North Dakota.

We do not have any off-balance-sheet arrangements or any material relationships with unconsolidated entities or financial partnerships.

Critical Accounting Policies Involving Significant Estimates

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

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, valuation of forward energy contracts, unbilled electric revenues, MISO electric market residual load adjustments, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management

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has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors. A discussion of critical accounting policies is included under the caption Critical Accounting Policies Involving Significant Estimates on pages 32 through 34 of our 2007 Annual Report to Shareholders. There were no material changes in critical accounting policies or estimates during the quarter ended March 31, 2008.

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), we have filed cautionary statements identifying important factors that could cause our 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-Q and in future filings by the Company with the Securities and Exchange Commission, in our press releases and in oral statements, words such as may , will , expect , anticipate , continue , estimate , project , believes or sim 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.

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

We are subject to federal and state legislation, regulations and actions that may have a negative impact on our business and results of operations.

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

Future operating results of our electric segment will be impacted by the outcome of a rate case filed in Minnesota and rate rider filings with North Dakota and Minnesota for transmission and wind energy investments. The rate case was filed on October 1, 2007, requesting an overall increase in Minnesota rates of 6.7%. The filing includes a request for an interim rate increase of 5.4%, which went into effect on November 30, 2007. Interim rates will remain in effect for all Minnesota customers until the MPUC makes a final determination on the electric utility s request, which is expected by August 1, 2008. If final rates are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

Certain costs currently included in the FCA in retail rates may be excluded from recovery through the FCA but may be subject to recovery through rates established in a general rate case. Further, all, or portions of, gross margins on asset-based wholesale electric sales may become subject to refund through the FCA as a result of a general rate case.

Weather conditions or changes in weather patterns can adversely affect our operations and revenues.

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

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

Our electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

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

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Our electric segment has capitalized $9.1 million in costs related to the planned construction of a second electric generating unit at its Big Stone Plant site as of March 31, 2008. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

Federal and state environmental regulation could cause us to incur substantial capital expenditures which could result in increased operating costs.

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

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

Our manufacturer of wind towers operates in a market that has been influenced by the existence of a Federal Production Tax Credit. This tax credit is scheduled to expire on December 31, 2008. Should this tax credit not be renewed, the revenues and earnings of this business could be reduced.

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

Our ability to own and expand our nonelectric businesses could be limited by state law.

Competition is a factor in all of our businesses.

Economic uncertainty could have a negative impact on our future revenues and earnings.

Volatile financial markets and changes in our debt rating could restrict our ability to access capital and could increase borrowing costs and pension plan expenses.

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

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

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

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

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

Our health services businesses may not be able to retain or comply with the dealership arrangement and other agreements with Philips Medical.

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

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At March 31, 2008 we had exposure to market risk associated with interest rates because we had $122.2 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.25% under the Varistar Credit agreement and LIBOR plus 0.40% under the Electric Utility Credit Agreement. At March 31, 2008 we had limited exposure to market risk associated with commodity prices and changes in foreign currency exchange rates. Outstanding trade accounts receivable of the Canadian operations of IPH are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 32% of IPH sales in the first quarter of 2008 were outside the United States and the Canadian operations of IPH pays its operating expenses in Canadian dollars. DMI has market risk related to changes in foreign currency exchange rates at its plant in Fort Erie, Ontario because the plant pays its operating expenses in Canadian dollars.

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

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

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

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The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of March 31, 2008 the electric utility had recognized, on a pretax basis, $2,420,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value the electric utility s forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility s power services personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. Of the forward energy sales contracts that are marked to market as of March 31, 2008, 99.2% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $8,880 in unrealized losses recognized on the open sales contracts.

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

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

(in thousands)	March 31, 2008
Current Asset Marked-to-Market Gain	$ 8,030
Current Liability Marked-to-Market Loss	(5,610)
Net Fair Value of Marked-to-Market Energy Contracts	$ 2,420

(in thousands)	Year-to-Date March 31, 2008
Fair Value at Beginning of Year	$ 632
Amount Realized on Contracts Entered into in 2007 and Settled in 2008	(204)
Changes in Fair Value of Contracts Entered into in 2007	369
Net Fair Value of Contracts Entered into in 2007 at End of Period	797
Changes in Fair Value of Contracts Entered into in 2008	1,623
Net Fair Value End of Period	$ 2,420

The $2,420,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market on March 31, 2008 is expected to be realized on settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	2nd Quarter 2008	3rd Quarter 2008	4th Quarter 2008	Total
Net Gain	$ 995	$ 628	$ 797	$2,420

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We have credit risk associated with the nonperformance or nonpayment by counterparties to our forward energy purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty s financial strength. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of March 31, 2008 was $4.0 million. As of March 31, 2008 we had a net credit risk exposure of $8.2 million from 10 counterparties with investment grade credit ratings. We had no exposure at March 31, 2008 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor s), Baa3 (Moody s) or BBB- (Fitch).

The $8.2 million credit risk exposure includes net amounts due to the electric utility on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after March 31, 2008. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

IPH has market risk associated with the price of fuel oil and natural gas used in its potato dehydration process as IPH may not be able increase prices for its finished products to recover increases in fuel costs. In the third quarter of 2006, IPH entered into forward natural gas contracts on the New York Mercantile Exchange market to hedge its exposure to fluctuations in natural gas prices related to approximately 50% of its anticipated natural gas needs through March 2007 for its Ririe, Idaho and Center, Colorado dehydration plants. These forward contracts were derivatives subject to mark-to-market accounting but they did not qualify for hedge accounting treatment. IPH included net changes in the market values of these forward contracts in net income as components of cost of goods sold in the period of recognition. Of the $371,000 in unrealized marked-to-market losses on forward natural gas contracts IPH had outstanding on December 31, 2006, $62,000 was reversed and $309,000 was realized on settlement in the first quarter of 2007.

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH s Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars on March 20, 2008 to cover approximately 50% of its monthly expenditures for the last nine months of 2008. Each contract is for the exchange of $400,000 USD for the amount of Canadian dollars stated in each contract, for a total exchange of $3,600,000 USD for $3,695,280 CAD. Each of these contracts can be settled incrementally during the month the contract is scheduled for settlement, but for practical reasons and to reduce settlement fees each contract will most likely be settled in one or two exchanges.

These open contracts are derivatives subject to mark-to-market accounting. IPH does not enter into these contracts for speculative purposes or with the intent of early settlement, but for the purpose of locking in acceptable exchange rates and hedging its exposure to future fluctuations in exchange rates with the intent of settling these contracts during their stated settlement periods and using the proceeds to pay its Canadian liabilities when they come due. These contracts will not qualify for hedge accounting treatment because the timing of their settlements will not coincide with the payment of specific bills or existing contractual obligations.

These foreign currency exchange forward contracts were valued and marked to market on March 31, 2008 based on quoted exchange values of similar contracts that could be purchased on March 31, 2008. Based on those values, IPH s Canadian subsidiary recorded a derivative liability and mark-to-market loss of $6,000 as of, and for the three month period ending, March 31, 2008.

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Item 4. Controls and Procedures

Under the supervision and with the participation of the Company s management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of March 31, 2008, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of March 31, 2008.

During the fiscal quarter ended March 31, 2008, there were no changes in the Company s internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is the subject of various pending or threatened legal actions and proceedings in the ordinary course of its business. Such matters are subject to many uncertainties and to outcomes that are not predictable with assurance. The Company records a liability in its consolidated financial statements for costs related to claims, including future legal costs, settlements and judgments, where it has assessed that a loss is probable and an amount can be reasonably estimated. The Company believes that the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under the caption Risk Factors and Cautionary Statements on pages 28 through 31 of the Company s 2007 Annual Report to Shareholders, which is incorporated by reference to Part I, Item 1A, Risk Factors in the Company s Annual Report on Form 10-K for the year ended December 31, 2007.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The Company does not have a publicly announced stock repurchase program. The following table shows common shares that were surrendered to the Company by employees to pay taxes in connection with shares issued for stock performance awards granted to executive officers and the vesting of restricted stock granted to employees under the Company s 1999 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
January 2008		
February 2008	20,139	$ 33.01
March 2008	68	$ 31.795
Total	20,207	

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Item 6. Exhibits

31.1 Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements 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
(Chief Financial
Officer/Authorized Officer)

Dated: May 12, 2008

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EXHIBIT INDEX

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