OTTER TAIL CORP
Form 10-Q
August 08, 2008

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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 June 30, 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:

July 31, 2008 30,172,396 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-

	June 30, 2008	December 31, 2007
	(Thousands of dollars)	
Current Assets		
Cash and Cash Equivalents	$	$ 39,824
Accounts Receivable:		
Trade Net	154,456	151,446
Other	17,527	14,934
Inventories	112,233	97,214
Deferred Income Taxes	7,216	7,200
Accrued Utility and Cost-of-Energy Revenues	13,402	32,501
Costs and Estimated Earnings in Excess of Billings	70,578	42,234
Other	30,531	15,299
Total Current Assets	405,943	400,652
Investments	9,200	10,057
Other Assets	25,139	24,500
Goodwill	107,228	99,242
Other Intangibles Net	36,470	20,456
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	6,537	6,986
Regulatory Assets and Other Deferred Debits	40,157	38,837
Total Deferred Debits	46,694	45,823
Plant		
Electric Plant in Service	1,051,644	1,028,917
Nonelectric Operations	306,755	257,590
Total Plant	1,358,399	1,286,507
Less Accumulated Depreciation and Amortization	528,725	506,744
Plant Net of Accumulated Depreciation and Amortization	829,674	779,763
Construction Work in Progress	96,806	74,261
Net Plant	926,480	854,024
Total	$ 1,557,154	$ 1,454,754

See accompanying notes to consolidated financial statements

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

	June 30, 2008	December 31, 2007
	(Thousands of dollars)	
Current Liabilities		
Short-Term Debt	$ 186,600	$ 95,000
Current Maturities of Long-Term Debt	3,376	3,004
Accounts Payable	148,317	141,390
Accrued Salaries and Wages	23,997	29,283
Accrued Taxes	9,194	11,409
Other Accrued Liabilities	20,566	13,873
Total Current Liabilities	392,050	293,959
Pensions Benefit Liability	40,637	39,429
Other Postretirement Benefits Liability	30,979	30,488
Other Noncurrent Liabilities	21,448	23,228
Deferred Credits		
Deferred Income Taxes	109,099	105,813
Deferred Tax Credits	17,790	16,761
Regulatory Liabilities	63,439	62,705
Other	316	275
Total Deferred Credits	190,644	185,554
Capitalization		
Long-Term Debt, Net of Current Maturities	341,630	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 30,124,709 and 2007 29,849,789	150,624	149,249
Premium on Common Shares	114,669	108,885
Retained Earnings	256,867	263,332
Accumulated Other Comprehensive Income	851	1,181

Total Common Equity	523,011	522,647
Total Capitalization	881,396	882,096
Total	$ 1,557,154	$ 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 June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
	(In thousands, except share and per share amounts)		(In thousands, except share and per share amounts)	
Operating Revenues				
Electric	$ 68,577	$ 70,498	$ 166,083	$ 160,351
Nonelectric	255,023	235,346	457,754	446,614
Total Operating Revenues	323,600	305,844	623,837	606,965
Operating Expenses				
Production Fuel Electric	14,808	14,077	34,712	30,502
Purchased Power Electric System Use	10,156	11,021	29,142	37,032
Electric Operation and Maintenance Expenses	27,757	26,651	54,500	53,526
Cost of Goods Sold Nonelectric (depreciation included below)	204,235	176,973	369,458	341,632
Other Nonelectric Expenses	36,242	31,377	70,989	62,135
Plant Closure Costs	1,412		1,412	
Depreciation and Amortization	16,124	12,947	31,037	26,040
Property Taxes Electric	2,563	2,527	5,187	5,053
Total Operating Expenses	313,297	275,573	596,437	555,920
Operating Income	10,303	30,271	27,400	51,045
Other Income	626	340	1,588	613
Interest Charges	7,043	5,026	13,754	9,894
Income Before Income Taxes	3,886	25,585	15,234	41,764
Income Taxes	369	9,482	3,487	15,253
Net Income	3,517	16,103	11,747	26,511
Preferred Dividend Requirements	184	184	368	368
Earnings Available for Common Shares	$ 3,333	$ 15,919	$ 11,379	$ 26,143
Earnings Per Common Share:				
Basic	$ 0.11	$ 0.54	$ 0.38	$ 0.88
Diluted	$ 0.11	$ 0.53	$ 0.38	$ 0.88
Average Number of Common Shares Outstanding:				

Basic	29,993,484	29,685,745	29,905,782	29,594,499
Diluted	30,300,207	29,940,868	30,198,967	29,843,953
Dividends Per Common Share	$ 0.2975	$ 0.2925	$ 0.5950	$ 0.5850

See accompanying notes to consolidated financial statements

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

	Six months ended June 30, 2008	Six months ended June 30, 2007
	(Thousands of dollars)	
Cash Flows from Operating Activities		
Net Income	$ 11,747	$ 26,511
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	31,037	26,040
Deferred Tax Credits	(782)	(568)
Deferred Income Taxes	5,959	1,016
Change in Deferred Debits and Other Assets	(2,627)	2,492
Discretionary Contribution to Pension Plan		(2,000)
Change in Noncurrent Liabilities and Deferred Credits	752	6,450
Allowance for Equity (Other) Funds Used During Construction	(801)	
Change in Derivatives Net of Regulatory Deferral	(655)	(1,620)
Stock Compensation Expense	1,908	1,097
Other Net	316	(390)
Cash Provided by (Used for) Current Assets and Current Liabilities:		
Change in Receivables	(1,904)	(24,558)
Change in Inventories	(10,082)	6,323
Change in Other Current Assets	(17,520)	(4,136)
Change in Payables and Other Current Liabilities	16,244	(28,190)
Change in Interest and Income Taxes Payable	1,348	11,858
Net Cash Provided by Operating Activities	34,940	20,325
Cash Flows from Investing Activities		
Capital Expenditures	(117,785)	(66,824)
Proceeds from Disposal of Noncurrent Assets	3,517	7,043
Acquisitions Net of Cash Acquired	(41,674)	(6,750)
Decreases (Increases) in Other Investments	(376)	(5,230)
Net Cash Used in Investing Activities	(156,318)	(71,761)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	3,636	4,649
Net Short-Term Borrowings	91,600	55,056
Proceeds from Issuance of Common Stock, Net of Issuance Expenses	5,176	5,805
Payments for Retirement of Common Stock	(91)	(295)
Proceeds from Issuance of Long-Term Debt	1,137	124
Debt Issuance Expenses	(19)	(123)
Payments for Retirement of Long-Term Debt	(1,829)	(1,543)
Dividends Paid	(18,212)	(17,711)
Net Cash Provided by Financing Activities	81,398	45,962

Effect of Foreign Exchange Rate Fluctuations on Cash	156	(1,317)
Net Change in Cash and Cash Equivalents	(39,824)	(6,791)
Cash and Cash Equivalents at Beginning of Period	39,824	6,791
Cash and Cash Equivalents at End of Period	$	$

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-month and six-month periods ended June 30, 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 33.6% for the three months ended June 30, 2008 compared with 30.0% for the three months ended June 30, 2007 and 31.0% for the six months ended June 30, 2008 compared with 27.6% for the six months ended June 30, 2007. The method used to determine the progress of completion is based on the ratio of labor hours incurred to total estimated labor hours 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.

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

(in thousands)	June 30, 2008	December 31, 2007
Costs Incurred on Uncompleted Contracts	$ 406,701	$ 286,358
Less Billings to Date	(404,020)	(292,692)
Plus Estimated Earnings Recognized	54,767	38,275
	$ 57,448	$ 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)	June 30, 2008	December 31, 2007
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 70,578	$ 42,234
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(13,130)	(10,293)
	$ 57,448	$ 31,941

Sales of Receivables

In March 2008, DMI Industries, Inc. (DMI), the Company s wind tower manufacturer, entered into a three-year $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation (GECC) on a revolving basis. Accounts receivable totaling $56.1 million have been sold in 2008. Discounts of $0.2 million for the six months ended June 30, 2008 were charged to operating expenses in the consolidated statements of income. In compliance with SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows.

Marketing and Sales Incentive Costs

ShoreMaster, Inc. (ShoreMaster), the Company s waterfront equipment manufacturer, provides dealer floor plan financing assistance for certain dealer purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer s order. ShoreMaster recognizes the estimated cost of projected interest payments related to each financed sale as a liability and a reduction of revenue at the time of sale, based on historical experience of the average length of time floor plan debt is outstanding, in accordance with Emerging Issues Task Force Issue No. 01-9, *Accounting for Consideration Given by a Vendor to a Customer (Including a Reseller of a Vendor s Products)*. The liability is reduced when interest is paid. To the extent current experience differs from previous estimates the accrued liability for financing assistance costs is adjusted accordingly. Financing assistance costs of $240,000 were charged to revenue for both the three- and six-month periods ended June 30, 2008.

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Supplemental Disclosures of Cash Flow Information

(in thousands)	Six Months Ended June 30, 2008	2007
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$(21,419)	$ 238
Cash Paid During the Period for:		
Interest (net of amount capitalized)	$ 11,924	$9,178
Income Taxes	$ 1,136	$1,138

Fair Value Measurements

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

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

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

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

The following table presents, for each of these hierarchy levels, the Company s assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2008:

(in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Investments of Nonqualified Retirement Savings Retirement Plan	$ 180	$ 10,995		$ 11,175
Cash Surrender Value of Keyman Life Insurance Policies Net of Policy Loans		10,528		10,528
Forward Energy Contracts		11,287		11,287
Investments of Captive Insurance Company:				
Corporate Debt Securities	3,850			3,850
U.S. Government Debt Securities	2,041			2,041
Forward Foreign Currency Exchange Contracts	15			15
Total Assets	$ 6,086	$ 32,810		$ 38,896
Liabilities:				

Forward Energy Contracts	$	$ 10,015	$ 10,015
Total Liabilities	$	$ 10,015	$ 10,015
Net Assets	$ 6,086	$ 22,795	$ 28,881

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Inventories

Inventories consist of the following:

(in thousands)	June 30, 2008	December 31, 2007
Finished Goods	$ 48,046	$ 38,952
Work in Process	8,541	5,218
Raw Material, Fuel and Supplies	55,646	53,044
	$ 112,233	$ 97,214

Goodwill and Other Intangible Assets

As a result of the acquisition of Miller Welding & Iron Works, Inc. (Miller Welding) by BTD Manufacturing, Inc. (BTD) in May 2008, Goodwill increased $7,986,000, Covenants Not to Compete increased by $100,000, Customer Relationships increased by $16,100,000 and Brand/Trade Name increased by $400,000. In the second quarter of 2008, ShoreMaster, Inc. (ShoreMaster) eliminated $282,000 of Covenants Not to Compete that were fully amortized.

The following table summarizes the components of the Company s other intangible assets at June 30, 2008 and December 31, 2007:

	June 30, 2008			December 31, 2007		
(in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets:						
Covenants Not to Compete	$ 2,456	$ 1,947	$ 509	$ 2,637	$ 2,113	$ 524
Customer Relationships	26,979	1,823	25,156	10,879	1,469	9,410
Other Intangible Assets Including Contracts	2,784	1,866	918	2,785	1,775	1,010
Total	$ 32,219	$ 5,636	$ 26,583	$ 16,301	$ 5,357	$ 10,944
Nonamortized Intangible Assets:						
Brand/Trade Name	$ 9,887	$	$ 9,887	$ 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 $563,000 for the six months ended June 30, 2008 compared to $687,000 for the six months ended June 30, 2007. The estimated annual amortization expense for these intangible assets for the next five years is $1,448,000 for 2008, $1,633,000 for 2009, $1,461,000 for 2010, $1,332,000 for 2011 and $1,312,000 for 2012.

Comprehensive Income

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2008	2007	2008	2007

Net Income	$ 3,517	$ 16,103	$ 11,747	$ 26,511
Other Comprehensive Income (net-of-tax)				
Foreign Currency Translation Gain (Loss)	77	942	(375)	1,046
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	37	44	80	88
Unrealized (Loss) Gain on Available-For-Sale Securities	(94)	2	(35)	(17)
Total Other Comprehensive Income (Loss)	20	988	(330)	1,117
Total Comprehensive Income	$ 3,537	$ 17,091	$ 11,417	$ 27,628

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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.

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

SFAS No. 141 (revised 2007), 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. Business Combination and Segment Information

Acquisition

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

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

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

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

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.

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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 Florida, Illinois, Minnesota, Missouri, North Dakota, Oklahoma, South Carolina and Ontario, Canada and sell products primarily in the United States.

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

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

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 11.0% of the Company s consolidated revenues for the six months ended June 30, 2008. No other single external customer accounts for 10% or more of the Company s revenues. Substantially all of the Company s long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
United States of America	97.2%	95.9%	96.6%	96.2%
Canada	1.5%	2.1%	1.4%	1.6%
All other countries (none greater than 1%)	1.3%	2.0%	2.0%	2.2%

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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- and six-month periods ended June 30, 2008 and 2007 and total assets by business segment as of June 30, 2008 and December 31, 2007 are presented in the following tables:

Operating Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2008	2007	2008	2007
Electric	$ 68,666	$ 70,572	$ 166,256	$ 160,552
Plastics	40,645	39,525	62,995	77,344
Manufacturing	120,342	104,786	217,937	191,011
Health Services	30,740	32,452	60,005	65,415
Food Ingredient Processing	15,913	18,403	31,811	37,898
Other Business Operations	48,080	40,587	86,190	75,733
Corporate Revenues and Intersegment Eliminations	(786)	(481)	(1,357)	(988)
Total	$ 323,600	$ 305,844	$ 623,837	$ 606,965

Interest Expense

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2008	2007	2008	2007
Electric	$ 3,133	$ 2,388	$ 6,114	$ 4,891
Plastics	327	323	468	508
Manufacturing	2,231	2,180	4,377	3,984
Health Services	176	255	355	460
Food Ingredient Processing	31	42	41	133
Other Business Operations	295	243	602	442
Corporate and Intersegment Eliminations	850	(405)	1,797	(524)
Total	$ 7,043	$ 5,026	$ 13,754	$ 9,894

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2008	2007	2008	2007
Electric	$ (266)	$ 2,679	$ 6,154	$ 5,905
Plastics	429	2,280	854	4,140
Manufacturing	618	3,660	15	5,205
Health Services	(11)	528	(426)	1,222
Food Ingredient Processing	614	710	1,214	949
Other Business Operations	543	758	(617)	817
Corporate	(1,558)	(1,133)	(3,707)	(2,985)

Total	$ 369	$ 9,482	$ 3,487	$ 15,253

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Earnings Available for Common Shares

(in thousands)	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Electric	$ 3,092	$ 4,892	$ 15,658	$ 10,630
Plastics	652	3,398	1,272	6,226
Manufacturing	1,396	5,335	780	7,874
Health Services	(88)	708	(779)	1,656
Food Ingredient Processing	685	1,543	1,808	1,992
Other Business Operations	794	1,157	(971)	1,234
Corporate	(3,198)	(1,114)	(6,389)	(3,469)
Total	$ 3,333	$ 15,919	$ 11,379	$ 26,143

Total Assets

(in thousands)	June 30, 2008	December 31, 2007
Electric	$ 848,287	$ 813,565
Plastics	97,746	77,971
Manufacturing	332,699	274,780
Health Services	63,132	64,824
Food Ingredient Processing	98,056	91,966
Other Business Operations	77,564	72,258
Corporate	39,670	59,390
Total	$ 1,557,154	$ 1,454,754

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%. 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 revised its proposal to credit asset-based wholesale margins through base rates, and made other adjustments to its request reducing its overall requested increase to 6.3%.

In an order issued by the Minnesota Public Utilities Commission (MPUC) on August 1, 2008 the electric utility was granted an increase in Minnesota retail electric rates of approximately 2.9%, compared with a requested increase of approximately 6.7%. Otter Tail Power Company will refund Minnesota customers the difference between interim rates and final rates, with interest. The refund will commence within 120 days after the final order is no longer subject to appeal. After the refund is commenced, it must be completed within 90 days. Amounts refundable totaling $2.2 million have been recorded as a liability on the Company s consolidated balance sheet as of June 30, 2008. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. The electric utility disagrees with certain aspects of the MPUC decision and plans to request reconsideration of those decision items.

The electric utility reversed and deferred recognition of $1.5 million in rate case-related costs in June 2008 that are subject to amortization and recovery over three years under new rates as ordered by the MPUC.

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Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt (kv) transmission lines. Evidentiary hearings for the Certificate of Need for the three CapX 2020 345-kv transmission line projects began in July 2008 and continued into August 2008. The MPUC is expected to decide if the lines meet regulatory need requirements by early 2009. 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 completed (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading these projects, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. Otter Tail Power Company is directly involved in two of these three projects and serves as the lead utility in a fourth Group 1 project, the Bemidji-Grand Rapids 230-kv line which has an expected in-service date of 2012-2013.

The electric utility filed a Certificate of Need for the fourth project on March 17, 2008. The Department of Commerce Office of Energy Security (OES) staff completed briefing papers regarding the Bemidji/Grand Rapids route permit application. The OES staff recommended to the MPUC that: (1) the route permit application be found to be complete, (2) the need determination not be sent to a contested case but be handled informally by MPUC review, and (3) the Certificate of Need and route permit proceedings be combined as requested. The MPUC met on June 26, 2008 to act on the OES staff recommendation. The MPUC agreed that the Certificate of Need and route permit applications were complete. The commissioners asked the CapX 2020 utilities to add a section to the Certificate of Need application addressing how the new Minnesota Conservation Improvement Programs (CIP) statutes will affect the need for the project. Because no one has intervened in the Certificate of Need proceeding, the MPUC will handle the Certificate of Need application as an uncontested case. The scoping hearing is scheduled for August 11-14, 2008. These hearings will combine the Certificate of Need and route permit scoping processes and will include federal agencies environmental scoping processes as well. The MPUC is expected to decide if this line is needed in the third or fourth quarter of 2008 and issue the route permit in 2009.

Renewable Energy Standards, Conservation and Renewable Resource Riders In February 2007, the Minnesota legislature passed a renewable energy standard requiring the electric utility to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. The electric utility has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. The electric utility s compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

Under the Next Generation Energy Act 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 received MPUC approval of its proposed rider on August 7, 2008. As of June 30, 2008 the electric utility had recorded a regulatory asset of $1,523,000 related to the deferred recognition of the Minnesota portion of renewable resource costs incurred in the first six months of 2008, pending approval and implementation of the proposed rider.

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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 in 2008.

North Dakota

On May 21, 2008 the North Dakota Public Service Commission (NDPSC) approved the electric utility s request for a Renewable Resource Cost Recovery Rider to enable the electric utility to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The Renewable Resource Adjustment of 0.193 cents per kilowatt-hour was included on North Dakota customers electric service statements beginning in June 2008. The first renewable energy project for which the electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became commercially operational in January 2008. The electric utility may also recover through this rider costs associated with other new renewable energy projects as they are completed.

Unlike renewable resource costs eligible for recovery in Minnesota, the electric utility had not been deferring recognition of its renewable resource costs eligible for recovery under the North Dakota Renewable Resource Cost Recovery Rider but has been charging those costs to operating expense since January 2008. After approval of the rider, the electric utility accrued revenue related to its investment in renewable energy and for renewable energy costs incurred since January 2008 that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider. The Company s June 30, 2008 consolidated balance sheet includes a regulatory asset of $1,361,000 for revenues that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider but that had not been billed to North Dakota customers as of June 30, 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 has not yet determined whether it will request recovery of such costs under the automatic adjustment mechanism or in its next general rate case filing.

The electric utility intends to file general rate cases requesting rate increases in both North Dakota and South Dakota in 2008.

Federal

Transmission Practices Audit The Federal Energy Regulatory Commission s (FERC) Office of Enforcement, formerly referred to as the Division of Operation Audits of the Office of Market Oversight and Investigations commenced an audit of the electric utility s transmission practices in 2005 for the period January 1, 2003 through August 31, 2005. The purpose of the audit was to determine whether the electric utility s transmission practices were in compliance with the FERC s applicable rules, regulations and tariff requirements and whether the implementation of the electric utility s waivers from the requirements of Order No. 889 and Order No. 2004 appropriately restricted access to transmission information that would benefit the electric utility s off-system sales. FERC staff identified two of the electric utility s transmission practices that it believed were out of compliance. The electric utility believes its actions were in compliance with the MISO tariff but rather than litigate, it entered into a Stipulated Settlement Agreement with FERC staff resolving all issues related to the audit. The FERC approved the settlement agreement on May 29, 2008.

FERC order (IN08-6-000) resolves alleged network transmission service violations by the electric utility of the Open Access Transmission and Energy Markets Tariff (OATT) of the MISO. The electric utility agreed to pay $547,000 plus interest of $141,000 to the Low Income Home Energy Assistance Program administered by the three states served by the electric utility. This amount represents profits earned by the electric utility on transactions FERC staff believes incorrectly utilized network transmission service under MISO s OATT. Enforcement staff did not seek to impose a compliance monitoring plan on the electric utility because the MISO s Day 2 market is now operational and its member utilities no longer schedule transmission within the system.

Big Stone II Project

On June 30, 2005 the electric utility and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant s nominal generating capacity from 630 megawatts to between 500 and 580 megawatts. New procedural schedules 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 Minnesota Department of Commerce 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.

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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. On May 19, 2008 the five Big Stone II participating utilities filed exceptions to the ALJs Report and Recommendation with the MPUC. The MPUC heard oral arguments on the Big Stone II transmission Certificate of Need application on June 3, 2008. In a 3-2 vote on June 5, 2008, the MPUC deferred a decision on the Big Stone II transmission Certificate of Need. The MPUC will develop a process whereby MPUC-appointed experts will render opinions on the modeling data utilized by the Big Stone II participating utilities for construction costs, potential carbon dioxide regulation costs, natural gas costs, and other matters pertinent to the application. The electric utility currently expects a decision on the transmission Certificate of Need application in late 2008 or 2009.

The electric utility s integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. On June 5, 2008 the MPUC also deferred approval of the electric utility s 2006-2020 IRP, which was originally filed in 2005.

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 NDPSC decision was delayed because of the change in ownership of the project. The ALJ in the matter held supplemental hearings in April 2008. The Company expects the NDPSC to issue a decision in the third quarter of 2008.

The Big Stone II participating utilities have filed a contested case proceeding with the South Dakota Board of Minerals and Environment to acquire required air permits for Big Stone II. A decision by the Board is expected in 2008.

As of June 30, 2008 the electric utility has capitalized $9.8 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.

Holding Company Reorganization

The Company s Board of Directors has authorized a holding company reorganization of the Company. Following the completion of the holding company reorganization, Otter Tail Power Company, which is currently operated as a division of Otter Tail Corporation, will be operated as a wholly owned subsidiary of the new parent holding company to be named Otter Tail Corporation. In connection with the reorganization, each outstanding Otter Tail Corporation common share will be automatically converted into one common share of the new holding company, and each outstanding Otter Tail Corporation cumulative preferred share will be automatically converted into one cumulative preferred share of the new holding company having the same terms. The holding company reorganization is subject to approval by Minnesota, North Dakota and South Dakota regulatory agencies and by the FERC, consents from various third parties and certain other conditions, and is expected to become effective on January 1, 2009.

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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)	June 30, 2008	December 31, 2007
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pension and Other Postretirement Benefits	$ 25,691	$ 26,933
Deferred Income Taxes	8,252	8,733
Accrued Cost-of-Energy Revenue	3,572	19,452
Reacquisition Premiums	3,546	3,745
Minnesota Renewable Resource Rider Recoverable Costs	1,523	
Minnesota General Rate Case Recoverable Expenses	1,460	
North Dakota Renewable Resource Rider Accrued Revenue	1,361	
MISO Schedule 16 and 17 Deferred Administrative Costs ND	704	576
MISO Schedule 16 and 17 Deferred Administrative Costs MN	664	855
Accumulated ARO Accretion/Depreciation Adjustment	449	345
Other Regulatory Assets	53	625
Deferred Marked-to-Market Losses		771
Total Regulatory Assets	$ 47,275	$ 62,035
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 58,765	$ 57,787
Deferred Income Taxes	4,532	4,502
Gain on Sale of Division Office Building	142	145
Deferred Marked-to-Market Gains		271
Total Regulatory Liabilities	$ 63,439	$ 62,705
Net Regulatory Liability Position	$ 16,164	$ 670

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 14 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 24.3 years.

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The deferred Minnesota Renewable Resource Rider Recoverable Costs are expected to be recovered from September 2008 through December 2009.

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

North Dakota Renewable Resource Rider Accrued Revenue relates to revenues earned on qualifying 2008 renewable resource costs incurred to serve North Dakota customers prior to the rider being implemented in June 2008. The North Dakota Renewable Resource Rider Accrued Revenue is expected to be recovered over 18 months, from July 2008 through December 2009.

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.

MISO Schedule 16 and 17 Deferred Administrative Costs MN will be recovered over the next 29 months.

Other Regulatory Assets will be amortized over the next 2.2 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 Accumulated Reserve for Estimated Removal Costs is reduced for actual removal costs incurred.

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 June 30, 2008 the electric utility had recognized, on a pretax basis, $1,272,000 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 June 30, 2008 and the change in the Company s consolidated balance sheet position from December 31, 2007 to June 30, 2008:

(in thousands)	June 30, 2008
Current Asset Marked-to-Market Gain	$ 11,287
Current Liability Marked-to-Market Loss	(10,015)
Net Fair Value of Marked-to-Market Energy Contracts	$ 1,272

(in thousands)	Year-to-Date June 30, 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	493
Net Fair Value of Contracts Entered into in 2007 at End of Period	921
Changes in Fair Value of Open Contracts Entered into in 2008	351
Net Fair Value End of Period	$ 1,272

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.

The foreign currency exchange forward contracts outstanding as of June 30, 2008 were valued and marked to market on June 30, 2008 based on quoted exchange values of similar contracts that could be purchased on June 30, 2008. Based on those values, IPH s Canadian subsidiary recorded a derivative asset and mark-to-market net gain of $15,000 as of, and for the three month period ended, June 30, 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.

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6. Common Shares and Earnings Per Share

Following is a reconciliation of the Company s common shares outstanding from December 31, 2007 through June 30, 2008:

Common Shares Outstanding, December 31, 2007	29,849,789
Issuances:	
Stock Options Exercised	191,774
Executive Officer Stock Performance Awards	62,625
Restricted Stock Issued to Nonemployee Directors	20,000
Restricted Stock Issued to Employees	19,371
Vesting of Restricted Stock Units	3,850
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(22,700)
Common Shares Outstanding, June 30, 2008	30,124,709

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- and six-month periods ended June 30, 2008 and 2007 there were no outstanding stock options which had exercise prices greater than the average market price. Therefore, all 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.

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.

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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.
Amounts of compensation expense recognized under the Company s six stock-based payment programs for the three- and six-month periods ended June 30, 2008 and 2007 are presented in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2008	2007	2008	2007
1999 Employee Stock Purchase Plan	$ 65	$ 64	$ 135	$ 127
Stock Options Granted Under the 1999 Stock Incentive Plan		22		90
Restricted Stock Granted to Directors	132	96	240	247
Restricted Stock Granted to Employees	121	208	239	412
Restricted Stock Units Granted to Employees	144	109	238	178
Stock Performance Awards Granted to Executive Officers	784	221	1,124	441
Totals	$ 1,246	$ 720	$ 1,976	$ 1,495

As of June 30, 2008 the remaining unrecognized compensation expense related to stock-based compensation was approximately $7.8 million (before income taxes) which will be amortized over a weighted-average period of 2.5 years.

9. Commitments and Contingencies

Ashtabula Wind Center

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.

Sales of Receivables

DMI entered into a three year $40 million receivable purchase agreement in March 2008, whereby designated customer accounts receivable may be sold to GECC on a revolving basis. As of June 30, 2008, DMI had sold $56.1 million of accounts receivable to GECC to mitigate accounts receivable concentration risk. Any obligations of DMI to GECC that may be incurred under the receivables purchase agreement are guaranteed by Varistar Corporation, DMI s parent company. As of June 30, 2008, $19.4 million of accounts receivable sold to GECC were outstanding.

Dealer Floor Plan Financing

Under ShoreMaster s floor plan financing agreement with GE Commercial Distribution Finance Corporation (CDF), ShoreMaster is required to repurchase new and unused inventory repossessed from ShoreMaster s dealers by CDF to satisfy the dealer s obligations to CDF. ShoreMaster has agreed to unconditionally guarantee to CDF all current and future liabilities which any dealer owes to CDF under this agreement. Any amounts due under this guaranty will be payable despite impairment or unenforceability of CDF s security interest with respect to inventory that may prevent CDF from repossessing the inventory. The aggregate total of amounts owed by dealers to CDF under this agreement was $5.4 million on June 30, 2008. ShoreMaster has incurred no losses under this agreement. The Company believes current available cash and cash generated from operations provide sufficient funding in the event there is a requirement to perform under this agreement.

Sierra Club Complaint

On June 10, 2008, the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleges certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleges the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleges the defendants actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club seeks both declaratory and injunctive relief to bring the defendants into compliance with the Clean Air Act and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. The ultimate outcome of these matters cannot be determined at this time.

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of June 30, 2008 will not be material.

11. Class B Stock Options of Subsidiary

As of June 30, 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 June 30,		Six Months Ended June 30,	
(in thousands)	2008	2007	2008	2007
Service Cost Benefit Earned During the Period	$ 1,275	$ 1,263	$ 2,550	$ 2,526
Interest Cost on Projected Benefit Obligation	2,800	2,733	5,600	5,466
Expected Return on Assets	(3,550)	(3,223)	(7,100)	(6,446)
Amortization of Prior-Service Cost	175	185	350	370
Amortization of Net Actuarial Loss	125	309	250	618
Net Periodic Pension Cost	$ 825	$ 1,267	$ 1,650	$ 2,534

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The Company did not make a contribution to its pension plan in the six months ended June 30, 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 June 30,		Six Months Ended June 30,	
(in thousands)	2008	2007	2008	2007
Service Cost Benefit Earned During the Period	$ 173	$ 157	$ 346	$ 313
Interest Cost on Projected Benefit Obligation	384	362	768	725
Amortization of Prior-Service Cost	16	17	32	34
Amortization of Net Actuarial Loss	120	135	240	270
Net Periodic Pension Cost	$ 693	$ 671	$ 1,386	$ 1,342

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 June 30,		Six Months Ended June 30,	
(in thousands)	2008	2007	2008	2007
Service Cost Benefit Earned During the Period	$ 300	$ 315	$ 600	$ 630
Interest Cost on Projected Benefit Obligation	725	698	1,450	1,396
Amortization of Transition Obligation	187	187	374	374
Amortization of Prior-Service Cost	50	(52)	100	(103)
Amortization of Net Actuarial Loss	125	129	250	258
Effect of Medicare Part D Expected Subsidy	(400)	(410)	(800)	(820)
Net Periodic Postretirement Benefit Cost	$ 987	$ 867	$ 1,974	$ 1,735

19. Subsequent Events

In an order issued by the MPUC on August 1, 2008 Otter Tail Power Company was granted an increase in Minnesota retail electric rates of approximately 2.9%, compared with a requested increase of approximately 6.7%. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. An interim rate increase of 5.4% went into effect on November 30, 2007. Otter Tail Power Company will refund Minnesota customers the difference between interim rates and final rates, with interest. Amounts refundable totaling $2.2 million have been recorded as a liability on the Company s consolidated balance sheet as of June 30, 2008. On July 30, 2008 Otter Tail Corporation, dba Otter Tail Power Company replaced its credit agreement with U.S. Bank National Association, which provided for a $75 million line of credit, with a new credit agreement providing for a $170 million line of credit with an accordion feature whereby the line can be increased to $250 million. The prior credit agreement was subject to renewal on September 1, 2008. The new credit agreement (the Electric Utility Credit Agreement) is between Otter Tail Corporation, dba Otter Tail Power Company and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S. Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. The Electric Utility Credit Agreement is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of the Company s senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of

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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 July 30, 2011.

On August 7, 2008 the MPUC approved the electric utility s request for a Renewable Resource Cost Recovery Rider that will enable the company to recover from its Minnesota retail customers its investments in renewable energy facilities. The effects of the approval of the rider on the Company s consolidated financial statements will be recorded in the third quarter of 2008 after the electric utility receives a final order with implementation guidance from the MPUC.

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

RESULTS OF OPERATIONS

Following is an analysis of our operating results by business segment for the three and six months ended June 30, 2008 and 2007, followed by our outlook for the remainder of 2008 and a discussion of changes in our consolidated financial position during the six months ended June 30, 2008.

Comparison of the Three Months Ended June 30, 2008 and 2007

Consolidated operating revenues were $323.6 million for the three months ended June 30, 2008 compared with $305.8 million for the three months ended June 30, 2007. Operating income was $10.3 million for the three months ended June 30, 2008 compared with $30.3 million for the three months ended June 30, 2007. The Company recorded diluted earnings per share of $0.11 for the three months ended June 30, 2008 compared to $0.53 for the three months ended June 30, 2007.

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 June 30, 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)	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007
Operating Revenues:		
Electric	$ 89	$ 74
Nonelectric	697	407
Cost of Goods Sold	599	393
Other Nonelectric Expenses	187	88

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Electric

(in thousands)	Three Months Ended June 30, 2008	2007	Change	% Change
Retail Sales Revenues	$ 57,389	$ 55,501	$ 1,888	3.4
Wholesale Revenues	6,221	6,674	(453)	(6.8)
Net Marked-to-Market (Loss) Gain	(31)	3,429	(3,460)	(100.9)
Other Revenues	5,087	4,968	119	2.4
Total Operating Revenues	$ 68,666	$ 70,572	$ (1,906)	(2.7)
Production Fuel	14,808	14,077	731	5.2
Purchased Power System Use	10,156	11,021	(865)	(7.8)
Other Operation and Maintenance Expenses	27,757	26,651	1,106	4.1
Depreciation and Amortization	7,806	6,250	1,556	24.9
Property Taxes	2,563	2,527	36	1.4
Operating Income	$ 5,576	$ 10,046	$ (4,470)	(44.5)

The increase in retail revenues reflects $1.5 million in North Dakota Renewable Resource Cost Recovery Rider revenue recorded in the second quarter of 2008 as a result of North Dakota Public Service Commission (NDPSC) approval of the electric utility s request for a Renewable Resource Cost Recovery Rider in May 2008. The increase in retail revenues also reflects a 2.7% increase in retail kilowatt-hour (kwh) sales related to a 24% increase in heating degree days between the quarters. 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 $1.5 million to retail revenues, but it was more than offset by a $2.2 million refund accrual resulting from the decision of the Minnesota Public Utilities Commission (MPUC) to grant a final general rate increase of only 2.9%. The refund accrual relates to interim rates in effect since November 30, 2007.

Wholesale electric revenues from company-owned generation were $4.9 million for the quarter ended June 30, 2008 compared with $3.5 million for the quarter ended June 30, 2007 as a result of a 37.5% increase in kwh sales and a 3.1% increase in the price per kwh sold. A slight increase in kwhs generated from company-owned resources resulted in more generation being available to meet wholesale market demands. 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 contracts settled in the second quarter of 2008 were $1.3 million compared with $3.2 million in the second quarter of 2007. Trading volumes were higher but profit margins on trades were significantly lower in the second quarter of 2008 compared to the second quarter of 2007. Additionally, second quarter 2007 energy trading revenues included the reversal of a $1.7 million refund accrual recorded in the first quarter of 2007.

The $3.5 million decrease in net marked-to-market gains on forward energy contracts reflects lower margins on trades in the second quarter of 2008 compared with the second quarter 2007 and second quarter 2008 reductions of marked-to-market gains recognized on open forward energy contracts in the first quarter of 2008.

Production fuel costs increased 5.2% despite a 2.8% decrease in kwhs generated as a result of an 8.2% increase in the cost of fuel per kwh generated. Generation for retail sales decreased 2.1% while generation used for wholesale electric sales increased 37.5% between the quarters. 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 Fuel Clause Adjustment (FCA) component of retail rates. The electric utility s 27 new wind turbines at the Langdon Wind Energy Center provided 4.5% of total kwh generation in the second quarter of 2008.

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The decrease in purchased power system use is due to a 13.5% reduction in kwhs purchased partially offset by a 6.5% increase in the cost per kwh purchased. 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 second quarter of 2008 compared with the second quarter of 2007.
Electric operating and maintenance expenses increased mainly as a result of expenses incurred in the second quarter of 2008 to repair and maintain the Hoot Lake Plant Unit 2 generator turbine. Depreciation expenses increased as a result of recent capital additions, including 27 new wind turbines at the Langdon Wind Energy Center.

Plastics

(in thousands)	Three Months Ended June 30, 2008	2007	Change	% Change
Operating Revenues	$ 40,645	$ 39,525	$ 1,120	2.8
Cost of Goods Sold	36,685	31,007	5,678	18.3
Operating Expenses	1,829	1,753	76	4.3
Depreciation and Amortization	723	764	(41)	(5.4)
Operating Income	$ 1,408	$ 6,001	$ (4,593)	(76.5)

Operating revenues for the plastics segment increased as result of a 1.1% increase in pounds of pipe sold combined with a 1.9% increase in the price per pound of pipe sold between the quarters. The increase in cost of goods sold reflects a 16.8% increase in resin prices per pound of pipe sold.

Manufacturing

(in thousands)	Three Months Ended June 30, 2008	2007	Change	% Change
Operating Revenues	$ 120,342	$ 104,786	$ 15,556	14.8
Cost of Goods Sold	99,377	81,188	18,189	22.4
Operating Expenses	10,213	9,108	1,105	12.1
Plant Closure Costs	1,412		1,412	
Depreciation and Amortization	4,876	3,283	1,593	48.5
Operating Income	$ 4,464	$ 11,207	$ (6,743)	(60.2)

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

Revenues at DMI Industries, Inc. (DMI) increased $13.0 million as a result of increases in production and sales activity, including first-year production from its new plant in Oklahoma.

Revenues at BTD Manufacturing, Inc. (BTD) increased $5.5 million, of which $4.2 million was from Miller Welding & Iron Works, Inc. (Miller Welding) acquired in May 2008. The remainder of BTD s revenue increase came from increased product sales to existing and new customers and increased prices related to higher raw material costs.

Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $1.1 million as a result of increased sales of horticultural products.

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Revenues at ShoreMaster, Inc. (ShoreMaster) decreased $4.1 million between the quarters mainly due to reduced sales of residential and commercial products, but also due to the completion of a marina project in California in early April 2008. Revenues from the California marina project decreased $0.9 million between the quarters.

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

DMI s cost of goods sold increased $14.6 million as a result of increases in production and sales activity, including first-year operations at its new plant in Oklahoma. DMI experienced a reduction in gross profit margins between the quarters mainly due to a slow start up of its Oklahoma plant where the levels of labor and overhead spending are higher than expected and production has not reached levels necessary to cover these costs. Increased gross profits in West Fargo and Fort Erie were offset by higher costs for overhead items like rentals and shop supplies. Cost of goods sold includes continued start-up costs at DMI s Oklahoma plant of $2.0 million incurred in the second quarter of 2008.

Cost of goods sold at BTD increased $4.3 million in relationship to their increased sales mainly in the categories of materials and labor costs. Miller Welding accounted for $3.5 million of the $4.3 million increase in cost of goods sold, including $0.7 million in fair valuation write-ups of acquired inventory that was sold in the second quarter of 2008. Under business combination accounting rules, acquired inventory is written up to fair value.

Cost of goods sold at T.O. Plastics increased $1.0 million, mainly in material costs related to increased sales of horticultural products.

Cost of goods sold at ShoreMaster decreased $1.7 million mainly due to reduced sales of residential and commercial products.

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

Operating expenses at DMI increased $1.0 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 $0.6 million as a result of increases in labor and benefit expenses and the May 2008 acquisition of Miller Welding.

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

ShoreMaster s operating expenses decreased $0.5 million as a result of reductions in professional services expenditures and bonus incentives.

The $1.4 million in plant closure costs in the second quarter of 2008 includes employee-related termination obligations, asset impairment costs and a reserve for additional expenses that will be incurred related to the closing of ShoreMaster s production facility in California following the completion of a major marina project in the state.

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

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Health Services

(in thousands)	Three Months Ended June 30, 2008	2007	Change	% Change
Operating Revenues	$ 30,740	$ 32,452	$ (1,712)	(5.3)
Cost of Goods Sold	24,128	23,849	279	1.2
Operating Expenses	5,534	6,111	(577)	(9.4)
Depreciation and Amortization	1,013	1,021	(8)	(0.8)
Operating Income	$ 65	$ 1,471	$ (1,406)	(95.6)

Revenues from scanning and other related services were down $1.9 million as the imaging side of the business continued to be affected by less than optimal utilization of certain imaging assets. Revenues from equipment sales and servicing increased $0.2 million between the quarters. The increase in cost of goods sold was directly related to the increase in equipment sales revenue. The decrease in operating expenses is the result of a $0.4 million gain on the sale of fixed assets in the second quarter of 2008 and decreases in sales and administrative salaries expenditures.

Food Ingredient Processing

(in thousands)	Three Months Ended June 30, 2008	2007	Change	% Change
Operating Revenues	$ 15,913	$ 18,403	$ (2,490)	(13.5)
Cost of Goods Sold	12,717	14,310	(1,593)	(11.1)
Operating Expenses	828	790	38	4.8
Depreciation and Amortization	1,071	999	72	7.2
Operating Income	$ 1,297	$ 2,304	$ (1,007)	(43.7)

The decrease in revenues in the food ingredient processing segment is due to a 19.4% decrease in pounds of product sold, partially offset by a 7.3% increase in the price per pound of product sold. Cost of goods sold decreased as a result of the decrease in sales, partially offset by a 10.3% increase in the cost per pound of product sold. The decrease in product sales was due to a reduction in sales to European customers and major snack customers. European sales were higher than normal in the second quarter of 2007 due to reduced crop yields in Europe in 2006. The increase in the cost per pound of product sold between the quarters is due to rising fuel oil and natural gas prices. 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 second quarter of 2007 to the second quarter of 2008.

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Other Business Operations

(in thousands)	Three Months Ended June 30, 2008	2007	Change	% Change
Operating Revenues	$ 48,080	$ 40,587	$ 7,493	18.5
Cost of Goods Sold	31,927	27,012	4,915	18.2
Operating Expenses	14,053	10,979	3,074	28.0
Depreciation and Amortization	497	502	(5)	(1.0)
Operating Income	$ 1,603	$ 2,094	$ (491)	(23.4)

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

Revenues at Foley Company increased $2.8 million due to higher backlog going into 2008 resulting in an increase in volume of jobs in progress.

Revenues at Midwest Construction Services, Inc. (MCS) increased $3.4 million as a result of an increase in jobs in progress between the quarters, especially in the area of electrical infrastructure connected to development and delivery of wind generated electricity.

Revenues at E.W. Wylie Corporation (Wylie) increased $1.3 million mainly as a result of the impact of increased fuel costs on shipping rates, but also as a result of a 2.2% increase in combined miles driven by company-owned and owner-operated trucks. Miles driven by company-owned trucks increased 24.5% as a result of the addition of heavy haul and wind tower transport services. Miles driven by owner-operated trucks decreased 34.8%.

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 $2.4 million, including increases of $1.7 million in labor and benefit costs, $0.3 million in subcontractor costs and $0.3 million in material costs, as a result of increased construction activity and jobs in progress.

Cost of goods sold at MCS increased $2.5 million between the quarters due to increases in material, direct labor and subcontractor costs directly related to MCS s increase in jobs in progress.

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

Wylie s operating expenses increased $1.5 million between the quarters. Fuel costs increased $2.0 million as a result of higher diesel fuel prices and an increase in miles driven by company-owned trucks. Labor costs increased by $0.3 million and equipment rental costs increased by $0.1 million due to the addition of heavy-haul services in the fourth quarter of 2007. Subcontractor expenses decreased $1.0 million as a result of the decrease in miles driven by owner-operated trucks.

MCS s operating expenses increased $1.2 million between the quarters mainly related to personnel changes and the hiring of additional employees and also due to increases in expenses for contracted services.

Foley Company s operating expenses increased $0.2 million between the quarters due to increases in labor and insurance costs.

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

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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.

(in thousands)	Three Months Ended June 30, 2008	2007	Change	% Change
Operating Expenses	$3,972	$2,724	$1,248	45.8
Depreciation and Amortization	138	128	10	7.8

The change in Corporate operating expenses includes increases in stock-based compensation, increases in outside professional services mainly related to the formation of a holding company and increases in claim loss provisions at our captive insurance company. Corporate expenses in the second quarter of 2007 included a $0.6 million gain on disposal of assets.

Interest Charges

Interest charges increased $2.0 million in the second quarter of 2008 compared with the second quarter of 2007 as a result of increases in average long-term and short-term debt outstanding between the quarters along with higher borrowing rates on short-term debt.

Other Income

The $0.3 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 second quarter of 2008 compared with the second quarter of 2007. The electric utility recorded no allowance for equity funds used in construction in the second 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 $9.1 million (96.1%) decrease in income taxes between the quarters is primarily due to a $21.7 million (84.8%) decrease in income before income taxes for the three months ended June 30, 2008 compared with the three months ended June 30, 2007. Federal production tax credits of $0.8 million and North Dakota wind tax credits of $0.1 million recorded in the second quarter of 2008 related to the electric utility s new wind turbines also contributed to the reduction in taxes between the quarters.

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Comparison of the Six Months Ended June 30, 2008 and 2007

Consolidated operating revenues were $623.8 million for the six months ended June 30, 2008 compared with $607.0 million for the six months ended June 30, 2007. Operating income was $27.4 million for the six months ended June 30, 2008 compared with $51.0 million for the six months ended June 30, 2007. The Company recorded diluted earnings per share of $0.38 for the six months ended June 30, 2008 compared to $0.88 for the six months ended June 30, 2007.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the six-month periods ended June 30, 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)	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Operating Revenues:		
Electric	$ 173	$ 201
Nonelectric	1,184	787
Cost of Goods Sold	1,065	762
Other Nonelectric Expenses	292	226

Electric

(in thousands)	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Change	% Change
Retail Sales Revenues	$ 144,689	$ 136,677	$ 8,012	5.9
Wholesale Revenues	9,805	10,908	(1,103)	(10.1)
Net Marked-to-Market Gain	2,219	3,398	(1,179)	(34.7)
Other Revenues	9,543	9,569	(26)	(0.3)
Total Operating Revenues	$ 166,256	$ 160,552	$ 5,704	3.6
Production Fuel	34,712	30,502	4,210	13.8
Purchased Power System Use	29,142	37,032	(7,890)	(21.3)
Other Operation and Maintenance Expenses	54,500	53,526	974	1.8
Depreciation and Amortization	15,514	12,920	2,594	20.1
Property Taxes	5,187	5,053	134	2.7
Operating Income	$ 27,201	$ 21,519	$ 5,682	26.4

The primary reason for the increase in retail revenues was a 5.7% increase in retail kwh sales resulting from colder weather in 2008. Heating degree days increased 11.4% in the first six months of 2008 compared with the first six months 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 that contributed approximately $3.7 million to retail revenues was partially offset by a $2.2 million refund accrual resulting from the MPUC s decision to grant a final general rate increase of 2.9%. The refund accrual relates to interim rates in effect since November 30, 2007. Retail revenues in 2008 also include $1.5 million in North Dakota Renewable Resource Cost Recovery Rider revenue recorded in the second quarter of 2008 as a result of NDPSC approval of the electric utility s request for a Renewable Resource Cost Recovery Rider in May 2008.

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Wholesale electric revenues from company-owned generation were $9.1 million for the six months ended June 30, 2008 compared with $9.5 million for the six months ended June 30, 2007. The decrease reflects a 17.8% reduction in the price per kwh sold mostly offset by a 15.9% increase in kwh sales. A 10.3% increase in kwhs generated from company-owned resources resulted in more generation being available to meet wholesale market demands. Plant availability, demand, load distribution and economic dispatch across the entire MISO region are all factors that drive wholesale prices of electricity. Net gains from energy trading contracts settled in the first six months of 2008 were $0.7 million compared with $1.4 million in the first six months of 2007. Trading volumes were higher but profit margins on trades were significantly lower between the periods.

The $1.2 million decrease in net marked-to-market gains on forward energy contracts reflects lower margins on trades in the first six months of 2008 compared with the first six months of 2007.

The increase in fuel costs reflects a 6.7% increase in kwhs generated at fuel-burning plants combined with a 6.6% increase in the cost of fuel per kwh generated. The electric utility was able to increase kwh output at its Big Stone Plant by 31.2% in the first six months of 2008 compared with the first six months 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 3.3% of total kwh generation in the first six months of 2008.

The decrease in purchased power system use is due to a 25.0% reduction in kwhs purchased partially offset by a 5.0% increase in the cost per kwh purchased. The decrease in kwh purchases for system use was directly related to the increase in kwhs generated at company-owned plants. The increase in the cost per kwh 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 six months of 2008 compared with the first six months of 2007 and increased generation costs mainly due to higher fuel prices.

Electric operating and maintenance expenses increased mainly as a result of expenses incurred in the second quarter of 2008 to repair and maintain the Hoot Lake Plant Unit 2 generator turbine. 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

	Six Months Ended June 30,			%
(in thousands)	2008	2007	Change	Change
Operating Revenues	$ 62,995	$ 77,344	$ (14,349)	(18.6)
Cost of Goods Sold	55,621	61,655	(6,034)	(9.8)
Operating Expenses	3,267	3,292	(25)	(0.8)
Depreciation and Amortization	1,518	1,529	(11)	(0.7)
Operating Income	$ 2,589	$ 10,868	$ (8,279)	(76.2)

Operating revenues for the plastics segment decreased mainly as result of a 21.1% decrease in pounds of pipe sold, partially offset by a 3.4% increase in the price per pound of pipe sold between the periods. 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 14.4% due to higher resin prices, resulting in a 40.2% decline in gross margins per pound of pipe sold.

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Manufacturing

(in thousands)	Six Months Ended June 30, 2008	2007	Change	% Change
Operating Revenues	$ 217,937	$ 191,011	$ 26,926	14.1
Cost of Goods Sold	182,225	150,434	31,791	21.1
Operating Expenses	20,536	17,039	3,497	20.5
Plant Closure Costs	1,412		1,412	
Depreciation and Amortization	8,625	6,393	2,232	34.9
Operating Income	$ 5,139	$ 17,145	$ (12,006)	(70.0)

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

Revenues at DMI increased $19.6 million as a result of increases in production and sales activity, including first-year production from its new plant in Oklahoma.

Revenues at BTD increased $8.6 million, of which $4.2 million was from Miller Welding acquired in May 2008. The remainder of BTD s revenue increase came from increased product sales to existing and new customers and increased prices related to higher raw material costs.

Revenues at T.O. Plastics increased $3.1 million as a result of increased sales of horticultural products.

Revenues at ShoreMaster, Inc. (ShoreMaster) decreased $4.4 million between the periods mainly due to reduced sales of residential and commercial products, but also due to the completion of a marina project in California in early April 2008. Revenues from the California marina project decreased $0.6 million between the periods.

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

DMI s cost of goods sold increased $23.7 million as a result of increases in production and sales activity, including initial operations at its new plant in Oklahoma. DMI experienced a $4.1 million reduction in gross profit margins between the periods mainly due to a slow start up of its Oklahoma plant where the levels of labor and overhead spending are higher than expected and production has not reached levels necessary to cover these costs. Included in cost of goods sold for the six months ended June 30, 2008 are costs of $2.8 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.

Cost of goods sold at BTD increased $6.9 million in relationship to their increased sales mainly in the categories of materials and supplies, labor and subcontractor costs. Miller Welding accounted for $3.5 million of the $6.9 million increase in cost of goods sold, including $0.7 million in fair valuation write-ups of acquired inventory that was sold in the second quarter of 2008. Under business combination accounting rules, acquired inventory is written up to fair value.

Cost of goods sold at T.O. Plastics increased $2.4 million, mainly in material costs related to increased sales of horticultural products.

Cost of goods sold at ShoreMaster decreased $1.2 million mainly due to reduced sales of residential and commercial products.

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

Operating expenses at DMI increased $1.9 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 $1.1 million as a result of increases in labor and benefit expenses and the May 2008 acquisition of Miller Welding.

ShoreMaster s operating expenses increased $0.5 million as a result of increases in sales and marketing expenses.

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

The $1.4 million in plant closure costs in 2008 includes employee-related termination obligations, asset impairment costs and a reserve for additional expenses that will be incurred related to the closing of ShoreMaster s production facility in California following the completion of a major marina project in the state.

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

Health Services

(in thousands)	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Change	% Change
Operating Revenues	$ 60,005	$ 65,415	$ (5,410)	(8.3)
Cost of Goods Sold	47,419	48,232	(813)	(1.7)
Operating Expenses	11,459	11,917	(458)	(3.8)
Depreciation and Amortization	1,995	1,983	12	0.6
Operating (Loss) Income	$ (868)	$ 3,283	$ (4,151)	(126.4)

Revenues from scanning and other related services were down $3.9 million as the imaging side of the business continued to be affected by less than optimal utilization of certain imaging assets. Revenues from equipment sales and servicing decreased $1.5 million between the periods, reflecting a trend away from distributor sales in favor of commission based manufacturer representative sales. The decrease in cost of goods sold was directly related to the decrease in equipment sales revenue. The decrease in operating expenses is due to a reduction in sales and marketing related expenditures.

Food Ingredient Processing

(in thousands)	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Change	% Change
Operating Revenues	$ 31,811	$ 37,898	$ (6,087)	(16.1)
Cost of Goods Sold	25,036	31,303	(6,267)	(20.0)
Operating Expenses	1,641	1,542	99	6.4
Depreciation and Amortization	2,144	1,968	176	8.9
Operating Income	$ 2,990	$ 3,085	$ (95)	(3.1)

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The decrease in revenues in the food ingredient processing segment is due to a 22.5% decrease in pounds of product sold, partially offset by an 8.4% increase in the price per pound of product sold. Cost of goods sold decreased as a result of the decrease in sales, partially offset by a 3.3% increase in the cost per pound of product sold. The decrease in product sales was due to a reduction in sales to European customers and major snack customers. European sales were higher than normal in 2007 due to reduced crop yields in Europe in 2006. The increase in the cost per pound of product sold between the periods is mainly due to rising fuel oil and natural gas prices. The increases in operating and depreciation and amortization expenses between the periods 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 half of 2007 to the first half of 2008.

Other Business Operations

(in thousands)	Six Months Ended June 30, 2008	2007	Change	% Change
Operating Revenues	$ 86,190	$ 75,733	$ 10,457	13.8
Cost of Goods Sold	60,222	50,770	9,452	18.6
Operating Expenses	26,066	21,592	4,474	20.7
Depreciation and Amortization	958	954	4	0.4
Operating (Loss) Income	$ (1,056)	$ 2,417	$ (3,473)	(143.7)

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

Revenues at Foley Company increased $7.0 million due to higher backlog going into 2008 resulting in an increase in volume of jobs in progress.

Revenues at MCS increased $1.8 million as a result of an increase in jobs in progress between the periods, especially in the area of electrical infrastructure connected to development and delivery of wind generated electricity.

Revenues at Wylie increased $1.7 million mainly as a result of the impact of increased fuel costs on shipping rates. Miles driven by company-owned trucks increased 24.2% as a result of the addition of heavy haul and wind tower transport services. Miles driven by owner-operated trucks decreased 40.2%. Combined miles driven by company-owned and owner-operated trucks decreased 0.5% between the periods.

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 $6.3 million, including increases of $4.1 million in subcontractor and material costs and $2.2 million in direct labor and benefit costs, as a result of increased construction activity and jobs in progress.

Cost of goods sold at MCS increased $3.1 million between the periods due to increases in labor, material and subcontractor costs directly related to MCS s increase in jobs in progress.

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

Wylie s operating expenses increased $2.4 million between the periods. Fuel costs increased $3.5 million as a result of higher diesel fuel prices and an increase in miles driven by company-owned trucks. Labor and benefit costs increased by $0.6 million and equipment rental costs increased by $0.2 million due to the addition of heavy-haul services in the fourth quarter of 2007. Subcontractor expenses decreased $2.0 million as a result of the decrease in miles driven by owner-operated trucks.

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MCS s operating expenses increased $1.3 million between the periods mainly related to personnel changes and the hiring of additional employees and also due to increases in expenses for contracted services.

Foley Company s operating expenses increased $0.3 million between the periods due to increases in labor and insurance costs.

Operating expenses at OTESCO increased $0.4 million between the periods related to the investigation and development of renewable energy wind-generation projects.

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.

	Six Months Ended June 30,			%
(in thousands)	2008	2007	Change	Change
Operating Expenses	$8,312	$6,979	$1,333	19.1
Depreciation and Amortization	283	293	(10)	(3.4)

The change in Corporate operating expenses includes increases in stock-based compensation, increases in outside professional services mainly related to the formation of a holding company and increases in claim loss provisions at our captive insurance company. Corporate expenses in 2007 included a $0.6 million gain on disposal of assets.

Interest Charges

Interest charges increased $3.9 million in the first six months of 2008 compared with the first six months of 2007 as a result of increases in both average long-term debt outstanding and average short-term debt outstanding between the periods along with higher borrowing rates on short-term debt.

Other Income

The $1.0 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 six months of 2008 compared with the first six months of 2007. The electric utility recorded no allowance for equity funds used in construction in the first six months of 2007 because its average balance of construction work in progress was less than average short-term borrowings during the same period.

Income Taxes

The $11.8 million (77.1%) decrease in income taxes between the periods is primarily the result of a $26.5 million (63.5%) decrease in income before income taxes for the six months ended June 30, 2008 compared with the six months ended June 30, 2007. Federal production tax credits of $1.3 million and North Dakota wind tax credits of $0.1 million recorded in the first six months of 2008 related to the electric utility s new wind turbines also contributed to the reduction in taxes between the periods.

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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 $1.40 to $1.65 of diluted earnings per share from our previously announced range of $1.75 to $2.00. Contributing to the revised 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 the 2.9% rate increase granted in Minnesota and rate riders for wind energy and transmission investments in North Dakota and Minnesota. The increase also anticipates 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 the sluggish housing and construction markets. Announced capacity expansions are not expected to have a material impact on 2008 results.

We expect a decrease in net income in our manufacturing segment in 2008. Increased capacity related to recent expansions and acquisitions as well as the start-up of DMI s wind tower manufacturing plant in Oklahoma in 2008 are expected to result in increased levels of revenue. DMI is investing in new facilities and incurring costs related to starting up and expanding facilities as well as integrating new customers in order to prepare for the anticipated growth in the wind industry subsequent to 2008. This is expected to result in a decrease in net income in 2008 compared with 2007. Also, the impact of a softening economy on ShoreMaster is expected to cause a decrease in net income for this segment in 2008. Backlog in place on June 30, 2008 in the manufacturing segment to support revenues for the remainder of 2008 is approximately $206 million. This compares with $191 million in revenue earned in the third and fourth quarters of 2007. DMI Industries accounts for a substantial portion of the 2008 backlog.

We expect a decline in net income from our health services segment in 2008 due to lower utilization levels of certain imaging assets.

We expect net income from our food ingredient processing business to be on par with 2007. This business has backlog in place as of June 30, 2008 of 51 million pounds for the remainder of 2008 compared with 52 million pounds in the third and fourth quarters of 2007.

We expect our other business operations segment to have higher net income in 2008 compared with 2007. Backlog for the construction businesses at the end of the second quarter of 2008 was approximately $79 million for the remainder of 2008 compared with $93 million in revenue in the third and fourth quarters of 2007.

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

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 and $121 million for planned investment in 48 megawatts of new wind energy generation, to reduce borrowings under our lines of credit, including borrowings used to finance DMI s plant additions and BTD s acquisition of 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 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 megawatts 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 1.5%, 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 June 30, 2008, $145.0 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.

As of June 30, 2008 Otter Tail Corporation, dba Otter Tail Power Company had a credit agreement with U.S. Bank National Association providing for a separate $75 million line of credit. As of June 30, 2008, $41.6 million was borrowed under this line of credit. Effective July 30, 2008 this credit agreement was replaced with a new credit agreement (the Electric Utility Credit Agreement) between Otter Tail Corporation, dba Otter Tail Power Company and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a

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Bank and as Syndication Agent, providing for a separate $170 million line of credit. The Electric Utility Credit Agreement is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of our senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement is subject to renewal on July 30, 2011.

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 were in compliance with all of the covenants under our financing agreements as of June 30, 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 June 30, 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 General Electric Capital Corporation on a revolving basis. Accounts receivable totaling $56.1 million have been sold in 2008. Discounts of $0.2 million for the six months ended June 30, 2008 were charged to operating expenses in the consolidated statements of income. The balance of receivables sold that were still outstanding to the buyer as of June 30, 2008 was $19.4 million. In compliance with Statement of Financial Accounting Standards (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.

In December 2007, ShoreMaster entered into an agreement with GE Commercial Distribution Finance Corporation (CDF) to provide floor plan financing for certain dealer purchases of ShoreMaster products. Financings under this agreement began in 2008. This agreement improves our liquidity by financing dealer purchases of ShoreMaster s products without requiring substantial use of working capital. ShoreMaster is paid by CDF shortly after product shipment for purchases financed under this agreement. The floor plan financing agreement requires ShoreMaster to repurchase new and unused inventory repossessed by CDF to satisfy the dealer s obligations to CDF under this agreement. ShoreMaster has agreed to unconditionally guarantee to CDF all current and future liabilities which any dealer owes to CDF under this agreement. Any amounts due under this guaranty will be payable despite impairment or unenforceability of CDF s security interest with respect to inventory that may prevent CDF from repossessing the inventory. The aggregate total of amounts owed by dealers to CDF under this agreement was $5.4 million on June 30, 2008. ShoreMaster has incurred no losses under this agreement. We believe current available cash and cash generated from operations provide sufficient funding in the event there is a requirement to perform under this agreement.

As part of its marketing programs ShoreMaster pays floor plan financing costs of its dealers for CDF financed purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer s order.

Cash provided by operating activities was $34.9 million for the six months ended June 30, 2008 compared with cash provided by operating activities of $20.3 million for the six months ended June 30, 2007. The $14.6 million increase in cash from operating activities includes a $26.8 million decrease in cash used for working capital items from $38.7 million in the first six months of 2007 to $11.9 million in the first six months of 2008 and a $2.0 million reduction in discretionary cash contributions to our pension fund, offset by a $14.8 million decrease in net income. Cash flows from Changes in Receivables increased by $22.7 million. This was mostly the result of the initiation of DMI s sales of receivables and ShoreMaster s floor plan financing program in 2008.

Major uses of funds for working capital items in the first six months of 2008 were an increase in Other Current Assets of $17.5 million and an increase in Inventories of $10.1 million, partially offset by an increase in Payables and Other Current Liabilities of $16.2 million. The $17.5 million increase in Other Current Assets includes: (1) a $28.3 million increase in costs in excess of billings, mainly at DMI, as a result of increased production activity, (2) a $4.0 million increase in income taxes receivable, and (3) a $3.8 million increase in prepaid insurance across all companies related to the timing of 2008 annual premium payments, offset by (4) a $19.1 million decrease in accrued utility revenues related to a decrease in unbilled revenue due to milder weather in June 2008 compared to December 2007, a reduction in accrued fuel clause adjustment (FCA) revenues related to increased availability of Big Stone Plant in the first six months of 2008 and a 1¢/kwh shift in recovery of fuel costs in Minnesota from the FCA to interim rates. The $10.1 million increase in Inventories is mainly related to a seasonal build up of finished goods inventory at IPH and our plastic pipe companies. The $16.2 million increase in payables and other current liabilities is mainly due to a $17.3 million an increase in Trade Accounts Payable at DMI as a result of increased production activity from the new plant in Oklahoma and expansion of manufacturing capacity in Fort Erie, Ontario.

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Net cash used in investing activities was $156.3 million for the six months ended June 30, 2008 compared with $71.8 million for the six months ended June 30, 2007. Cash used for capital expenditures increased by $51.0 million between the periods. Cash used for capital expenditures at the electric utility increased by $46.1 million, mainly due to payments for assets at the Langdon Wind Energy Center and the Ashtabula Wind Center. Cash used for capital expenditures at Northern Pipe Products, Inc. increased $2.9 million related to the installation of a new polyvinyl chloride (PVC) pipe extrusion line at their Hampton, Iowa plant. Cash used for capital expenditures increased by $1.9 million in our Food Ingredient Processing segment related to the expansion of a warehouse at the Center, Colorado plant. We paid $41.7 million in cash to acquire Miller Welding in May 2008. The Company completed two acquisitions during the first six months of 2007 for a combined purchase price of $6.8 million.

Net cash provided by financing activities was $81.4 million for the six months ended June 30, 2008 compared with $46.0 million for the six months ended June 30, 2007. Proceeds from short-term borrowings and checks written in excess of cash were $95.2 million in the first six months of 2008 compared with proceeds from short-term borrowings and checks written in excess of cash of $59.7 million in the first six months of 2007. Proceeds from the issuance of common stock were $5.2 million in the first six months of 2008 compared with $5.8 million in the first six months of 2007. During the first six months of 2008 the Company issued 191,774 common shares for stock options exercised compared with 226,241 common shares issued for stock options exercised in the first six months of 2007. Dividends paid on common and preferred shares in the first six months of 2008 were $18.2 million compared with $17.7 million in the first six months of 2007. The increase in dividend payments is due to a one cent per share increase in common dividends paid and an increase in common shares outstanding between the periods.

Due to the approval of additional capital expenditures in 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	$ 194	$ 880
Plastics	13	21
Manufacturing	52	114
Health Services	2	11
Food Ingredient Processing	4	18
Other Business Operations	4	9
Corporate		1
Total	$ 269	$ 1,054

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

Other 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 megawatts 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.

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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 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 June 30, 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.
- Any significant impairment of our goodwill would cause a decrease in our assets and a reduction in our net operating performance.
- Future operating results of the electric segment will be impacted by the outcome of rate rider filings in Minnesota for transmission and wind energy investments.
- Certain costs currently included in the FCA in retail rates may be excluded from recovery through the FCA but may be subject to recovery through rates established in a general rate case. Further, all, or portions of, gross

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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.

Our electric segment has capitalized $9.8 million in costs related to the planned construction of a second electric generating unit at its Big Stone Plant site as of June 30, 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 our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where the electric utility provides service or through increased market prices for electricity.

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 be unable to renew and continue to maintain the dealership arrangements with Philips Medical which are scheduled to expire on December 31, 2008.

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 June 30, 2008 we had exposure to market risk associated with interest rates because we had $186.6 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.5% under the Varistar Credit agreement and LIBOR plus 0.40% under the electric utility s line of credit. At June 30, 2008 we had limited exposure to 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 28% of IPH sales in the first half 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 June 30, 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 June 30, 2008, annualized interest expense and pre-tax earnings would change by approximately $104,000.

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

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

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

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of June 30, 2008 the electric utility had recognized, on a pretax basis, $1,272,000 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 June 30, 2008, 99.8% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $85,000 in unrealized gains 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 June 30, 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 June 30, 2008 and the change in our consolidated balance sheet position from December 31, 2007 to June 30, 2008:

(in thousands)	June 30, 2008
Current Asset Marked-to-Market Gain	$ 11,287
Current Liability Marked-to-Market Loss	(10,015)
Net Fair Value of Marked-to-Market Energy Contracts	$ 1,272

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(in thousands)	Year-to-Date June 30, 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	493
Net Fair Value of Contracts Entered into in 2007 at End of Period	921
Changes in Fair Value of Contracts Entered into in 2008	351
Net Fair Value End of Period	$ 1,272

The $1,272,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market on June 30, 2008 is expected to be realized on settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	3rd Quarter 2008	4th Quarter 2008	Total
Net Gain	$ 396	$ 876	$ 1,272

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 June 30, 2008 was $5.7 million. As of June 30, 2008 we had a net credit risk exposure of $11.1 million from ten counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. We had no exposure at June 30, 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 $11.1 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 June 30, 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.

The foreign currency exchange forward contracts outstanding as of June 30, 2008 were valued and marked to market on June 30, 2008 based on quoted exchange values of similar contracts that could be purchased on June 30, 2008. Based on those values, IPH s Canadian subsidiary recorded a derivative asset and mark-to-market net gain of $15,000 as of, and for the six-month period ended, June 30, 2008.

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 June 30, 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 June 30, 2008.

During the fiscal quarter ended June 30, 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

On June 10, 2008, the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleges certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleges the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleges the defendants actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club seeks both declaratory and injunctive relief to bring the defendants into compliance with the Clean Air Act and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. The ultimate outcome of these matters cannot be determined at this time.

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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 one material addition to 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.

Any significant impairment of our goodwill would cause a decrease in our assets and a reduction in our net operating performance.

We had approximately $107.2 million of goodwill recorded on our consolidated balance sheet as of June 30, 2008. We have recorded goodwill for businesses in each of our business segments, except for our electric utility. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of these businesses, we may be forced to record an impairment charge, which would lead to decreased assets and a reduction in net operating performance. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, future business operating performance, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects or other assumptions could affect the fair value of one or more business segments, which may result in an impairment charge.

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 previously issued common shares that were surrendered to the Company by employees to pay taxes in connection with the vesting of restricted stock granted to such employees under the Company s 1999 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
April 2008	2,493	$ 35.64
May 2008		
June 2008		
Total	2,493	

Item 4. Submission of Matters to a Vote of Security Holders

The Annual Meeting of Shareholders of the Company was held on April 14, 2008, to consider and act upon the following matters: (1) to elect three nominees to the Board of Directors with terms expiring in 2011, and (2) to ratify the appointment of Deloitte & Touche LLP as the Company s independent registered public accounting firm for the fiscal year ending December 31, 2008. All nominees for directors as listed in the proxy statement were elected. The names of each other director whose term of office continued after the meeting are as follows: Karen M. Bohn, Arvid R. Liebe, John C. MacFarlane, Edward J. McIntyre, and Joyce Nelson Schuette and Gary Spies.

The voting results are as follows:

Election of Directors	Shares Voted For	Shares Voted Withheld Authority	Broker Non-Votes
John D. Erickson	22,437,950	2,731,376	-0-
Nathan I. Partain	21,787,661	3,381,666	-0-
James B. Stake	22,389,762	2,779,564	-0-

	Shares Voted For	Shares Voted Against	Shares Voted Abstain	Broker Non-Votes
Ratification of Deloitte & Touche LLP as Independent Registered Public Accounting Firm	24,665,084	306,792	197,451	-0-

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: August 8, 2008

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EXHIBIT INDEX

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