OTTER TAIL CORP
Form 10-Q
November 07, 2008

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

(Mark One)

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

For the quarterly period ended September 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 (Do not check if a smaller reporting company)	Smaller reporting company o

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:

October 31, 2008 35,384,620 Common Shares ($5 par value)

OTTER TAIL CORPORATION
INDEX

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2008	December 31, 2007
	(Thousands of dollars)	
Current Assets		
Cash and Cash Equivalents	$ 17,862	$ 39,824
Accounts Receivable:		
Trade Net	171,681	151,446
Other	22,636	14,934
Inventories	111,042	97,214
Deferred Income Taxes	6,904	7,200
Accrued Utility and Cost-of-Energy Revenues	14,207	32,501
Costs and Estimated Earnings in Excess of Billings	60,616	42,234
Other	23,953	15,299
Total Current Assets	428,901	400,652
Investments	8,120	10,057
Other Assets	24,108	24,500
Goodwill	106,778	99,242
Other Intangibles Net	35,977	20,456
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	6,784	6,986
Regulatory Assets and Other Deferred Debits	41,024	38,837
Total Deferred Debits	47,808	45,823
Plant		
Electric Plant in Service	1,066,957	1,028,917
Nonelectric Operations	306,181	257,590
Total Plant	1,373,138	1,286,507
Less Accumulated Depreciation and Amortization	538,693	506,744
Plant Net of Accumulated Depreciation and Amortization	834,445	779,763
Construction Work in Progress	127,937	74,261
Net Plant	962,382	854,024
Total	$ 1,614,074	$ 1,454,754

See accompanying notes to consolidated financial statements

Table of Contents

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

	September 30, 2008	December 31, 2007
	(Thousands of dollars)	
Current Liabilities		
Short-Term Debt	$ 111,955	$ 95,000
Current Maturities of Long-Term Debt	3,389	3,004
Accounts Payable	128,547	141,390
Accrued Salaries and Wages	27,507	29,283
Accrued Taxes	10,248	11,409
Other Accrued Liabilities	14,284	13,873
Total Current Liabilities	295,930	293,959
Pensions Benefit Liability	39,537	39,429
Other Postretirement Benefits Liability	31,378	30,488
Other Noncurrent Liabilities	21,157	23,228
Deferred Credits		
Deferred Income Taxes	111,256	105,813
Deferred Tax Credits	17,527	16,761
Regulatory Liabilities	64,066	62,705
Other	330	275
Total Deferred Credits	193,179	185,554
Capitalization		
Long-Term Debt, Net of Current Maturities	340,667	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 35,384,470 and 2007 29,849,789	176,922	149,249
Premium on Common Shares	240,996	108,885
Retained Earnings	257,327	263,332
Accumulated Other Comprehensive Income	226	1,181
Total Common Equity	675,471	522,647
Total Capitalization	1,032,893	882,096

Total	$ 1,614,074	$ 1,454,754

See accompanying notes to consolidated financial statements

-3-

Table of Contents

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(In thousands, except share and per share amounts)		(In thousands, except share and per share amounts)	
Operating Revenues				
Electric	$ 82,821	$ 72,052	$ 248,904	$ 232,403
Nonelectric	270,098	230,183	727,852	676,797
Total Operating Revenues	352,919	302,235	976,756	909,200
Operating Expenses				
Production Fuel Electric	18,732	16,994	53,444	47,496
Purchased Power Electric System Use	10,456	6,499	39,598	43,531
Electric Operation and Maintenance Expenses	33,091	27,212	87,591	80,738
Cost of Goods Sold Nonelectric (depreciation included below)	213,999	179,868	583,457	521,500
Other Nonelectric Expenses	37,222	30,211	108,211	92,346
Plant Closure Costs	883		2,295	
Depreciation and Amortization	16,563	13,366	47,600	39,406
Property Taxes Electric	2,227	2,538	7,414	7,591
Total Operating Expenses	333,173	276,688	929,610	832,608
Operating Income	19,746	25,547	47,146	76,592
Other Income	1,157	619	2,745	1,232
Interest Charges	7,269	4,927	21,023	14,821
Income Before Income Taxes	13,634	21,239	28,868	63,003
Income Taxes	4,003	7,907	7,490	23,160
Net Income	9,631	13,332	21,378	39,843
Preferred Dividend Requirements	184	184	552	552
Earnings Available for Common Shares	$ 9,447	$ 13,148	$ 20,826	$ 39,291
Earnings Per Common Share:				
Basic	$ 0.31	$ 0.44	$ 0.69	$ 1.33
Diluted	$ 0.31	$ 0.44	$ 0.69	$ 1.31
Average Number of Common Shares Outstanding:				

Basic	30,513,578	29,745,600	30,108,381	29,644,866
Diluted	30,817,013	29,995,660	30,398,235	29,887,510
Dividends Per Common Share	$ 0.2975	$ 0.2925	$ 0.8925	$ 0.8775

See accompanying notes to consolidated financial statements

Table of Contents

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

	Nine months ended September 30, 2008	2007
	(Thousands of dollars)	
Cash Flows from Operating Activities		
Net Income	$ 21,378	$ 39,843
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	47,600	39,406
Deferred Tax Credits	(1,180)	(852)
Deferred Income Taxes	9,123	2,706
Change in Deferred Debits and Other Assets	(2,162)	(484)
Discretionary Contribution to Pension Plan	(2,000)	(4,000)
Change in Noncurrent Liabilities and Deferred Credits	1,795	6,116
Allowance for Equity (Other) Funds Used During Construction	(1,712)	
Change in Derivatives Net of Regulatory Deferral	(337)	(163)
Stock Compensation Expense	2,885	1,592
Other Net	580	(469)
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(24,314)	(26,883)
Change in Inventories	(9,054)	7,779
Change in Other Current Assets	(8,165)	3,562
Change in Payables and Other Current Liabilities	4,997	(15,194)
Change in Interest and Income Taxes Payable	810	4,382
Net Cash Provided by Operating Activities	40,244	57,341
Cash Flows from Investing Activities		
Capital Expenditures	(172,237)	(99,433)
Proceeds from Disposal of Noncurrent Assets	7,446	8,297
Acquisitions Net of Cash Acquired	(41,674)	(6,750)
Increases in Other Investments	(393)	(5,824)
Net Cash Used in Investing Activities	(206,858)	(103,710)
Cash Flows from Financing Activities		
Net Short-Term Borrowings	16,955	39,881
Proceeds from Issuance of Common Stock	162,961	7,633
Common Stock Issuance Expenses	(6,136)	
Payments for Retirement of Common Stock	(91)	(305)
Proceeds from Issuance of Long-Term Debt	1,140	25,128
Short-Term and Long-Term Debt Issuance Expenses	(527)	(328)
Payments for Retirement of Long-Term Debt	(2,691)	(2,445)
Dividends Paid	(27,382)	(26,601)

Net Cash Provided by Financing Activities	144,229	42,963
Effect of Foreign Exchange Rate Fluctuations on Cash	423	(2,681)
Net Change in Cash and Cash Equivalents	(21,962)	(6,087)
Cash and Cash Equivalents at Beginning of Period	39,824	6,791
Cash and Cash Equivalents at End of Period	$ 17,862	$ 704

See accompanying notes to consolidated financial statements

Table of Contents

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 nine-month periods ended September 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 34.6% for the three months ended September 30, 2008 compared with 33.3% for the three months ended September 30, 2007 and 32.3% for the nine months ended September 30, 2008 compared with 29.5% for the nine months ended September 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.

Table of Contents

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

(in thousands)	September 30, 2008	December 31, 2007
Costs Incurred on Uncompleted Contracts	$ 518,863	$ 286,358
Less Billings to Date	(528,496)	(292,692)
Plus Estimated Earnings Recognized	63,801	38,275
	$ 54,168	$ 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)	September 30, 2008	December 31, 2007
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 60,616	$ 42,234
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(6,448)	(10,293)
	$ 54,168	$ 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 on a revolving basis. Accounts receivable totaling $90.9 million have been sold in 2008. Discounts of $0.5 million for the nine months ended September 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 $98,000 for the three months ended September 30, 2008 and $338,000 for the nine months ended September 30, 2008 were charged to revenue.

Supplemental Disclosures of Cash Flow Information

(in thousands)	Nine Months Ended September 30, 2008	2007
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$(21,117)	$ 1,631
Cash Paid During the Period for:		
Interest (net of amount capitalized)	$ 19,925	$11,899
Income Taxes	$ 1,779	$18,896

Table of Contents

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 September 30, 2008:

(in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Investments for Nonqualified Retirement Savings Retirement Plan:				
Money Market and Mutual Funds and Cash	$ 1,049			$ 1,049
Cash Surrender Value of Life Insurance Policies		$ 9,211		9,211
Cash Surrender Value of Keyman Life Insurance Policies Net of Policy Loans		10,235		10,235
Forward Energy Contracts		4,922		4,922
Investments of Captive Insurance Company:				
Corporate Debt Securities	3,707			3,707
U.S. Government Debt Securities	1,323			1,323
Total Assets	$ 6,079	$ 24,368		$ 30,447
Liabilities:				
Forward Energy Contracts		$ 3,427		$ 3,427
Forward Foreign Currency Exchange Contracts	$ 114			114
Total Liabilities	$ 114	$ 3,427		$ 3,541
Net Assets	$ 5,965	$ 20,941		$ 26,906

Table of Contents

Inventories

Inventories consist of the following:

(in thousands)	September 30, 2008	December 31, 2007
Finished Goods	$ 45,492	$ 38,952
Work in Process	11,044	5,218
Raw Material, Fuel and Supplies	54,506	53,044
	$ 111,042	$ 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 eliminated $282,000 of fully amortized Covenants Not to Compete. As a result of the sale of certain imaging assets and routes in the Health Services segment in the third quarter of 2008, Goodwill was reduced by $450,000 and $200,000 of fully amortized Covenants Not to Compete were eliminated.

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

	September 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	$ 2,256	$ 1,817	$ 439	$ 2,637	$ 2,113	$ 524
Customer Relationships	26,946	2,130	24,816	10,879	1,469	9,410
Other Intangible Assets Including Contracts	2,785	1,944	841	2,785	1,775	1,010
Total	$ 31,987	$ 5,891	$ 26,096	$ 16,301	$ 5,357	$ 10,944
Nonamortized Intangible Assets:						
Brand/Trade Name	$ 9,881	$	$ 9,881	$ 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 $1,023,000 for the nine months ended September 30, 2008 compared to $985,000 for the nine months ended September 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	Nine Months Ended

(in thousands)	September 30, 2008	2007	September 30, 2008	2007
Net Income	$ 9,631	$ 13,332	$ 21,378	$ 39,843
Other Comprehensive Income (net-of-tax)				
Foreign Currency Translation (Loss) Gain	(579)	571	(954)	1,617
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	37	43	117	131
Unrealized (Loss) Gain on Available-For-Sale Securities	(83)	5	(118)	(12)
Total Other Comprehensive (Loss) Income	(625)	619	(955)	1,736
Total Comprehensive Income	$ 9,006	$ 13,951	$ 20,423	$ 41,579

Table of Contents

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.

Table of Contents

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.

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

Table of Contents

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

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

Food Ingredient Processing consists of 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 4 Canadian provinces.

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

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

The Company has a customer within the Manufacturing segment that accounted for approximately 10.2% of the Company s consolidated revenues for the nine months ended September 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 September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
United States of America	97.9%	97.8%	97.1%	96.7%
Canada	1.1%	0.9%	1.3%	1.4%
All other countries (none greater than 1%)	1.0%	1.3%	1.6%	1.9%

Table of Contents

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

Operating Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2008	2007	2008	2007
Electric	$ 82,883	$ 72,110	$ 249,139	$ 232,662
Plastics	36,690	36,975	99,685	114,319
Manufacturing	127,778	95,330	345,715	286,341
Health Services	31,139	31,360	91,144	96,775
Food Ingredient Processing	15,333	15,714	47,144	53,612
Other Business Operations	59,650	51,231	145,840	126,964
Corporate Revenues and Intersegment Eliminations	(554)	(485)	(1,911)	(1,473)
Total	$ 352,919	$ 302,235	$ 976,756	$ 909,200

Interest Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2008	2007	2008	2007
Electric	$ 3,158	$ 2,465	$ 9,272	$ 7,356
Plastics	369	242	838	750
Manufacturing	2,659	2,141	7,035	6,125
Health Services	176	223	531	683
Food Ingredient Processing	46	34	87	167
Other Business Operations	331	315	933	757
Corporate and Intersegment Eliminations	530	(493)	2,327	(1,017)
Total	$ 7,269	$ 4,927	$ 21,023	$ 14,821

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2008	2007	2008	2007
Electric	$ 1,863	$ 3,595	$ 8,017	$ 9,500
Plastics	1,088	941	1,942	5,081
Manufacturing	288	2,359	303	7,564
Health Services	208	84	(218)	1,306
Food Ingredient Processing	(717)	942	497	1,891
Other Business Operations	2,908	935	2,291	1,752
Corporate	(1,635)	(949)	(5,342)	(3,934)

Total	$ 4,003	$ 7,907	$ 7,490	$ 23,160

Table of Contents

Earnings Available for Common Shares

(in thousands)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Electric	$ 6,335	$ 6,309	$ 21,993	$ 16,939
Plastics	1,641	1,384	2,913	7,610
Manufacturing	380	3,477	1,160	11,351
Health Services	254	53	(525)	1,709
Food Ingredient Processing	(1,074)	993	734	2,985
Other Business Operations	4,341	1,361	3,370	2,595
Corporate	(2,430)	(429)	(8,819)	(3,898)
Total	$ 9,447	$ 13,148	$ 20,826	$ 39,291

Total Assets

(in thousands)	September 30, 2008	December 31, 2007
Electric	$ 896,355	$ 813,565
Plastics	91,669	77,971
Manufacturing	340,178	274,780
Health Services	63,533	64,824
Food Ingredient Processing	92,978	91,966
Other Business Operations	84,546	72,258
Corporate	44,815	59,390
Total	$ 1,614,074	$ 1,454,754

3. Rate and Regulatory Matters

Minnesota

General Rate Case In an order issued by the Minnesota Public Utilities Commission (MPUC) on August 1, 2008 the electric utility was granted an increase in Minnesota retail electric rates of approximately 2.9%, compared with the originally requested increase of approximately 6.7%. An interim rate increase of 5.4% went into effect on November 30, 2007. The electric utility will refund Minnesota customers the difference between interim rates and final rates, with interest. 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 $3.1 million have been recorded as a liability on the Company s consolidated balance sheet as of September 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 disagreed with certain aspects of the MPUC decision and requested reconsideration of those items. Other participants requested reconsideration of other aspects of the decision.

On October 8, 2008 the MPUC rendered decisions on the five issues raised in these requests for reconsideration. The MPUC granted reconsideration on two issues but only changed its decision on the treatment of non-asset-based margins. Non-asset-based margins come from the unregulated side of the electric utility s business and, therefore, costs associated with non-asset-based sales activities should be excluded from recovery in retail rates. This can be accomplished by either assigning an amount of electric utility costs to the unregulated activity, thus removing those costs from retail rates, or by sharing non-asset-based margins with retail customers. The original MPUC decision reflected both practices. As a result of the MPUC decision on reconsideration, the electric utility will assign an amount of utility costs to the unregulated activity but will not be required to share non-asset-based margins with retail customers. The original MPUC decision would have required the electric utility to share 10% of actual non-asset-based margins through a fuel clause adjustment mechanism, rather than as a reduction to revenue requirements and base rates. Therefore, this decision did not change the amount of the base rate increase granted on August 1, 2008. The MPUC s written order dated August 1, 2008, reflects the final approved revenue increase of $3.8 million, or about 2.9%. The final revenue increase is 44% of the increase originally requested by the electric utility.

The electric utility expects to implement final rates in January 2009 and to begin interim rate refunds in February 2009. The electric utility reversed and deferred recognition of $1.5 million in rate case-related filing and administrative costs in June 2008 that are subject to amortization and recovery over three years under new rates as ordered by the MPUC.

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 MPUC is expected to determine if there is a need for this line in the fourth quarter of 2008 and, if appropriate, 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.

Table of Contents

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.

In an order issued on August 15, 2008, the MPUC approved the electric utility s proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in renewable energy facilities. The rider enables the electric utility to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Renewable Resource Adjustment of 0.19 cents per kilowatt-hour (kwh) was included on Minnesota customers electric service statements beginning in September 2008. The first renewable energy project for which the electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The Company s June 30, 2008 consolidated balance sheet included a regulatory asset of $1.5 million for deferred recognition of the Minnesota portion of renewable resource costs. As a result of the MPUC approval, the electric utility reversed and expensed the $1.5 million of deferred costs in the third quarter of 2008 and has recognized a regulatory asset of $2.7 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of September 30, 2008.

The electric utility has requested that a decision on its 2009 Rider Adjustment filing be delayed until January 1, 2009 with an expected implementation date of April 1, 2009, so that investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center, scheduled to be commercially operational by January 2009, can be considered for inclusion in the 2009 Rider Adjustment.

In addition to the Renewable Resource Cost Recovery Rider, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new electric transmission facilities. The MPUC may approve a tariff 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 plans to file a proposed rider with the MPUC to recover its share of costs of eligible transmission infrastructure upgrades projects in the fourth quarter of 2008.

North Dakota

Renewable Resource Cost Recovery Rider 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 Cost Recovery Rider Adjustment of 0.193 cents per kwh was included on North Dakota customers electric service statements beginning in June 2008. The first renewable energy project for which the electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The electric utility may also recover through this rider costs associated with other new renewable energy projects as they are completed. The electric utility has included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center scheduled to be commercially operational by January 2009 in its 2009 annual request to the NDPSC to increase the amount of the Renewable Resource Cost Recovery Rider Adjustment.

Table of Contents

The electric utility had not been deferring recognition of its renewable resource costs eligible for recovery under the North Dakota Renewable Resource Cost Recovery Rider but had been charging those costs to operating expense since January 2008. After approval of the rider, the electric utility has accrued revenues related to its investment in renewable energy and for renewable energy costs incurred since January 2008 that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider. The Company s September 30, 2008 consolidated balance sheet includes a regulatory asset of $1.7 million for revenues that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider but that had not been billed to North Dakota customers as of September 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 plans to request recovery of such costs under the automatic adjustment mechanism in the fourth quarter of 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), issued May 29, 2008, 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 were established in the various project-related proceedings, which take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

Table of Contents

In the fourth quarter of 2005, the participating utilities filed applications with the MPUC for a transmission Certificate of Need and a Route Permit for the Minnesota portion of the Big Stone II transmission line. 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.

On May 9, 2008 the ALJs issued a 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. The MPUC decision on these matters was expected in June 2008, but in a 3-2 vote on June 5, 2008, the MPUC deferred its decision on the Big Stone II transmission Certificate of Need for purposes of obtaining additional expert opinion on three issues: carbon regulation costs, construction costs and fuel costs.

On October 22, 2008, the MPUC made public the report of the expert, Boston Pacific Company, Inc. (Boston Pacific). In addition to minor differences in estimated costs of construction and fuel, Boston Pacific recommended a significant increase in the range of carbon regulation costs utilized in the Big Stone II utilities modeling. The Big Stone II utilities used a carbon dioxide emission cost range of $4 to $30 per ton adopted by the MPUC for utilities to use in resource planning dockets. The Boston Pacific report recommends modeling a range of carbon regulation costs of up to $60 per ton and states that the modeling should apply the costs as a tax, given the uncertainty of cost estimates associated with potential cap and trade regimes.

Hearings on the Boston Pacific report are scheduled to be held in November 2008 before a Minnesota ALJ. The ALJ s summary report is expected in late December 2008 and MPUC deliberations are expected to begin in January 2009. The electric utility currently expects a decision on the transmission Certificate of Need application in the first quarter of 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, originally filed in 2005. The addition of 160 megawatts of wind generation in the IRP was approved early in 2007. The electric utility and Montana-Dakota Utilities Co. also made a filing for an advance determination of prudence on Big Stone II with the NDPSC, and on August 27, 2008 the NDPSC determined that the electric utility s participation in Big Stone II was prudent in a range of 121.8 to 130 megawatts. In addition, the Big Stone II participating utilities have filed a contested case proceeding with the South Dakota Board of Minerals and Environment to acquire air permits for Big Stone II. A decision by the South Dakota Board of Minerals and Environment is expected in 2008. Delays in approval of the Big Stone II transmission Certificate of Need in Minnesota and issuance of required permits may delay the availability of Big Stone II as a generation resource. The electric utility is assessing ways in which to address this potential near-term generation shortfall.

As of September 30, 2008 the electric utility has capitalized $10.8 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, a portion of these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

Table of Contents

Holding Company Reorganization

The Company s Board of Directors has authorized a holding company reorganization of the Company s regulated utility business. Following the completion of the holding company reorganization, Otter Tail Power Company, which is currently operated as a division of Otter Tail Corporation, will be operated as a wholly owned subsidiary of the new parent holding company to be named Otter Tail Corporation. In connection with the reorganization, each outstanding Otter Tail Corporation common share will be automatically converted into one common share of the new holding company, and each outstanding Otter Tail Corporation cumulative preferred share will be automatically converted into one cumulative preferred share of the new holding company having the same terms. The holding company reorganization is subject to approval by Minnesota, North Dakota and South Dakota regulatory agencies and by the FERC, consents from various third parties and certain other conditions. In an order issued on August 18, 2008, the FERC authorized the reorganization subject to certain conditions specified in the order. In an order issued on October 10, 2008, the NDPSC approved the Company s application to form a holding company. In a meeting held on October 30, 2008, the South Dakota Public Utilities Commission (SDPUC) approved the Company s application to form a new holding company. A hearing in Minnesota is not expected until December 2008 or later.

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)	September 30, 2008	December 31, 2007
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pension and Other Postretirement Benefits	$ 25,217	$ 26,933
Deferred Income Taxes	8,012	8,733
Accrued Cost-of-Energy Revenue	4,286	19,452
Debt Reacquisition Premiums	3,446	3,745
Minnesota Renewable Resource Rider Accrued Revenues	2,741	
North Dakota Renewable Resource Rider Accrued Revenues	1,662	
Minnesota General Rate Case Recoverable Expenses	1,457	
MISO Schedule 16 and 17 Deferred Administrative Costs ND	756	576
MISO Schedule 16 and 17 Deferred Administrative Costs MN	595	855
Accumulated ARO Accretion/Depreciation Adjustment	502	345
Deferred Marked-to-Market Losses	271	771
Plant Acquisition Costs	74	107
Deferred Conservation Improvement Program (Revenues) Costs	(263)	518
Total Regulatory Assets	$ 48,756	$ 62,035
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 58,894	$ 57,787
Deferred Income Taxes	4,349	4,502
Deferred Marked-to-Market Gains	682	271
Gain on Sale of Division Office Building	141	145

Total Regulatory Liabilities	$	64,066	$	62,705
Net Regulatory Liability Position	$	15,310	$	670

Table of Contents

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 23 months.

Debt Reacquisition Premiums included in Unamortized Debt Expense are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 24 years.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 renewable resource costs incurred to serve Minnesota customers since January 1, 2008 that have not been billed to Minnesota customers as of September 30, 2008. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over 15 months, from October 2008 through December 2009.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 renewable resource costs incurred to serve North Dakota customers since January 1, 2008 that have not been billed to North Dakota customers as of September 30, 2008. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over 15 months, from October 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.

MISO Schedule 16 and 17 Deferred Administrative Costs ND were excluded from recovery through the Fuel Clause Adjustment (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 general rate case filed in North Dakota in November 2008.

MISO Schedule 16 and 17 Deferred Administrative Costs MN will be recovered over the next 26 months.

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

All Deferred Marked-to-Market Losses and Gains recorded as of September 30, 2008 are related to forward purchases of energy scheduled for delivery prior to March 2009.

Plant Acquisition Costs will be amortized over the next 20 months.

Deferred Conservation Program Costs represent mandated conservation expenditures and incentives recoverable through retail electric rates over the next 21 months.

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

Table of Contents

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 September 30, 2008 the electric utility had recognized, on a pretax basis, $1,084,000 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.

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 September 30, 2008 and the change in the Company s consolidated balance sheet position from December 31, 2007 to September 30, 2008:

(in thousands)		September 30, 2008
Current Asset Marked-to-Market Gain	$	4,922
Regulatory Asset Deferred Marked-to-Market Loss		271
Total Assets		5,193
Current Liability Marked-to-Market Loss		(3,427)
Regulatory Liability Deferred Marked-to-Market Gain		(682)
Total Liabilities		(4,109)
Net Fair Value of Marked-to-Market Energy Contracts	$	1,084

(in thousands)		Year-to-Date September 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		570
Net Fair Value of Contracts Entered into in 2007 at End of Period		998
Changes in Fair Value of Open Contracts Entered into in 2008		86
Net Fair Value End of Period	$	1,084

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH s Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in March 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.

Table of Contents

In July 2008, IPH s Canadian subsidiary entered into additional forward contracts for the exchange of U.S. dollars into Canadian dollars to cover approximately 50% of its monthly expenditures for the twelve-month period of August 2008 through July 2009. 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 $4,800,000 USD for $5,003,160 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 September 30, 2008 were valued and marked to market on September 30, 2008 based on quoted exchange values of similar contracts that could be purchased on September 30, 2008. Based on those values, IPH s Canadian subsidiary recorded a derivative liability of $114,000 as of September 30, 2008 and net mark-to-market losses of $106,000 in 2008. The fair value measurements of these forward energy contracts fall into level 1 of the fair value hierarchy set forth in SFAS No. 157.

6. Common Shares and Earnings Per Share

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

Common Shares Outstanding, December 31, 2007	29,849,789
Issuances:	
September 2008 Common Stock Offering	5,175,000
Stock Options Exercised	276,535
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, September 30, 2008	35,384,470

In September 2008 the Company completed a public offering of 5,175,000 common shares under its universal shelf registration statement filed with the Securities and Exchange Commission, including 675,000 common shares issued pursuant to the full exercise of the underwriters overallotment option. The public offering price was $30 per share. Net proceeds from the sale of the common shares after deducting underwriting discounts and commissions and offering expenses were $149.1 million. The net proceeds will be used to finance the construction of Otter Tail Power Company s 32 wind turbines and collector system at the Ashtabula Wind Center in Barnes County, North Dakota and the expansion of DMI s wind tower manufacturing facilities in Tulsa, Oklahoma and West Fargo, North Dakota.

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

Table of Contents

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 nine-month periods ended September 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 was $35.55 per share.

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2008	2007	2008	2007
1999 Employee Stock Purchase Plan	$ 75	$ 66	$ 210	$ 193
Stock Options Granted Under the 1999 Stock Incentive Plan				90
Restricted Stock Granted to Directors	110	103	350	350
Restricted Stock Granted to Employees	102	43	341	455
Restricted Stock Units Granted to Employees	149	103	387	281
Stock Performance Awards Granted to Executive Officers	562	221	1,686	662
Totals	$ 998	$ 536	$ 2,974	$ 2,031

As of September 30, 2008 the remaining unrecognized compensation expense related to stock-based compensation was approximately $6.9 million (before income taxes) which will be amortized over a weighted-average period of 2.4 years.

9. Commitments and Contingencies

Ashtabula Wind Center

On April 30, 2008 the electric utility 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 $121 million in 2008.

IPH Natural Gas Purchase Commitments

In August 2008, IPH entered into contracts with its natural gas suppliers for the firm purchase of natural gas to cover portions of its anticipated natural gas needs in Ririe, Idaho and Center, Colorado from September 2008 through August 2009 at fixed prices. Commitments under these contracts increase commitments 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 $1.1 million in 2008 and $1.3 million in 2009.

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 $3.5 million on September 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.

Table of Contents

Federal Power Act Complaint

On September 9, 2008, Renewable Energy System Americas, Inc. (RES), a developer of wind generation and PEAK Wind Development, LLC (PEAK Wind), a group of landowners in Barnes County, North Dakota, filed a complaint with FERC alleging that the electric utility and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act, (FPA) to deny RES/PEAK Wind access to the Pillsbury Line, an interconnection line that Minnkota is building with the electric utility as its contractor, to interconnect generation projects being developed by the electric utility and FPL Energy, Inc. RES/PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) that FERC direct MISO, to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that the electric utility, Minnkota and FPL Energy pay any costs associated with interconnecting the Glacier Ridge Project to the MISO transmission system which would result from the interconnection of the Pillsbury Line to the Minnkota transmission system, and that FERC assess civil penalties against the electric utility. The electric utility answered the Complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that FERC dismiss the Complaint. On October 14, 2008, RES and PEAK Wind filed an Answer to the electric utility s Answer and, restated the allegations included in the initial Complaint. RES and PEAK Wind also added a request that FERC rescind both the electric utility s waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, the electric utility filed a Reply, denying the allegations made by RES and PEAK Wind in its Answer. The Company believes the claims that the electric utility has violated the FPA are without merit. The ultimate outcome of this matter cannot be determined at this time.

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 September 30, 2008 will not be material.

10. Short-Term and Long-Term Borrowings

Short-Term Debt

On July 30, 2008 Otter Tail Corporation, dba Otter Tail Power Company replaced its credit agreement with U.S. Bank National Association, which provided for a $75 million line of credit, with a new credit agreement providing for a $170 million line of credit with an accordion feature whereby the line can be increased to $250 million as described in the new credit agreement. The 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 0.5%, subject to adjustment based on the ratings of the Company s senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement is subject to renewal on July 30, 2011.

11. Class B Stock Options of Subsidiary

As of September 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:

(in thousands)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Service Cost Benefit Earned During the Period	$ 922	$ 1,102	$ 3,472	$ 3,628
Interest Cost on Projected Benefit Obligation	2,894	2,626	8,494	8,092
Expected Return on Assets	(3,376)	(3,265)	(10,476)	(9,711)
Amortization of Prior-Service Cost	207	187	557	557
Amortization of Net Actuarial Loss	(124)	200	126	818
Net Periodic Pension Cost	$ 523	$ 850	$ 2,173	$ 3,384

The Company made a $2.0 million discretionary contribution to its pension plan in the third quarter of 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:

(in thousands)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Service Cost Benefit Earned During the Period	$ 172	$ 157	$ 518	$ 470
Interest Cost on Projected Benefit Obligation	383	362	1,151	1,087
Amortization of Prior-Service Cost	18	17	50	51
Amortization of Net Actuarial Loss	120	135	360	405
Net Periodic Pension Cost	$ 693	$ 671	$ 2,079	$ 2,013

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:

(in thousands)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Service Cost Benefit Earned During the Period	$ 227	$ 194	$ 827	$ 824
Interest Cost on Projected Benefit Obligation	567	528	2,017	1,924
Amortization of Transition Obligation	187	187	561	561
Amortization of Prior-Service Cost	58	(52)	158	(155)
Amortization of Net Actuarial Loss	(230)	(125)	20	133
Effect of Medicare Part D Expected Subsidy	(79)	(105)	(879)	(925)
Net Periodic Postretirement Benefit Cost	$ 730	$ 627	$ 2,704	$ 2,362

19. Subsequent Events

On October 31, 2008 the electric utility filed a general rate case in South Dakota requesting an overall revenue increase of approximately \$3.8 million, or 15.3%, which provides for recovery of renewable resource investments and expenses in base rates. South Dakota rules do not provide for interim rate increases pending approval of final rates. A final decision by the SDPUC on the electric utility s request is expected in mid-summer 2009.

On November 3, 2008 the electric utility filed a general rate case in North Dakota requesting an overall revenue increase of approximately \$6.1 million, or 5.1%, and an interim rate increase, to begin on January 2, 2009, of approximately 4.1%, or \$4.8 million annualized. A final decision by the NDPUC on the electric utility s request is expected in mid-summer 2009.

Table of Contents

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 nine months ended September 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 nine months ended September 30, 2008.

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

Consolidated operating revenues were $352.9 million for the three months ended September 30, 2008 compared with $302.2 million for the three months ended September 30, 2007. Operating income was $19.7 million for the three months ended September 30, 2008 compared with $25.5 million for the three months ended September 30, 2007. The Company recorded diluted earnings per share of $0.31 for the three months ended September 30, 2008 compared to $0.44 for the three months ended September 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 September 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 September 30, 2008	Three Months Ended September 30, 2007
Operating Revenues:		
Electric	$ 62	$ 58
Nonelectric	492	427
Cost of Goods Sold	535	425
Other Nonelectric Expenses	19	60

Electric

(in thousands)	Three Months Ended September 30, 2008	2007	Change	% Change
Retail Sales Revenues	$ 64,539	$ 59,896	$ 4,643	7.8
Wholesale Revenues	9,876	6,779	3,097	45.7
Net Marked-to-Market Gain (Loss)	65	(751)	816	108.7
Other Revenues	8,403	6,186	2,217	35.8
Total Operating Revenues	$ 82,883	$ 72,110	$ 10,773	14.9
Production Fuel	18,732	16,994	1,738	10.2
Purchased Power System Use	10,456	6,499	3,957	60.9
Other Operation and Maintenance Expenses	33,091	27,212	5,879	21.6
Depreciation and Amortization	7,864	6,581	1,283	19.5
Property Taxes	2,227	2,538	(311)	(12.3)
Operating Income	$ 10,513	$ 12,286	$ (1,773)	(14.4)

The increase in retail revenues reflects $4.0 million in Minnesota and North Dakota Renewable Resource Cost Recovery Rider revenue recorded in the third quarter of 2008. The electric utility billed and accrued $3.1 million in Minnesota Renewable Resource Cost Recovery Rider revenue for recovery of the Minnesota portion of the electric

utility s renewable energy expenses and investment costs going back to January 1, 2008 as a result of the Minnesota Public Utilities Commission s (MPUC) August 2008 approval of the electric utility s request for a Renewable Resource Cost Recovery Rider. North Dakota Renewable Resource Cost Recovery Rider revenues billed and accrued in the third quarter of 2008 totaled $0.9 million. The North Dakota Public Service Commission (NDPSC) approved the electric utility s request for a Renewable Resource Cost Recovery Rider in May 2008. The increase in retail revenues also includes $0.9 million attributable to an increase in Minnesota retail electric rates of approximately 2.9%, which was approved by the MPUC. These increases in retail revenues were partially offset by a decrease in revenues related to a 3.2% decrease in retail kilowatt-hour (kwh) sales resulting from a 17.3% reduction in cooling degree days between the quarters as the region experienced a milder summer in 2008 compared with summer 2007.

Wholesale electric revenues from company-owned generation were $9.1 million for the quarter ended September 30, 2008 compared with $5.7 million for the quarter ended September 30, 2007 as a result of a 37.7% increase in wholesale kwh sales combined with a 16.2% increase in the price per kwh sold. A decrease in kwhs generated to serve retail customers 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 decreased by $1.0 million in the third quarter of 2008 compared with the third quarter of 2007. Trading volumes were down only 1.8% but profit margins on trades decreased 59% between the quarters. Net revenue from the purchase and sale of Financial Transmission Rights increased $0.7 million between the quarters.

The $0.8 million reduction in net marked-to-market losses on forward energy contracts reflects third quarter 2007 reductions of marked-to-market gains recognized on open forward energy contracts in the first half of 2007.

Construction work completed for other entities on regional wind power projects contributed $2.6 million to the increase in other electric revenues in the third quarter of 2008 compared with the third quarter of 2007. Revenues from the sale of steam to an ethanol plant near Big Stone Plant decreased $0.4 million between the quarters as a result of the ethanol plant being shut down for maintenance in September 2008.

Production fuel costs increased 10.2% despite a 6.5% decrease in kwhs generated as a result of a 17.8% increase in the cost of fuel per kwh generated. Generation for retail sales decreased 9.4% while generation used for wholesale electric sales increased 37.7% between the quarters. The increase in fuel costs per kwh is related to higher prices for natural gas and fuel oil used to generate electricity and 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 wind turbines at the Langdon Wind Energy Center provided 3.0% of total kwh generation in the third quarter of 2008.

The increase in purchased power system use is due to a 39.2% increase in kwhs purchased combined with a 15.6% increase in the cost per kwh purchased. 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 fuel prices in the third quarter of 2008 compared with the third quarter of 2007.

The increase in other operating and maintenance expenses between the quarters includes: (1) a $2.3 million increase in costs related to contracted construction work completed for other entities on regional wind projects, (2) the recognition of $1.5 million in expenses recoverable through the Minnesota Resource Cost Recovery Rider that had been deferred in the first six months of 2008 pending approval of the rider in the third quarter of 2008, (3) $1.4 million in increased wage and benefit expenses, and (4) a $0.3 million increase in software licensing expenses.

Depreciation expenses increased as a result of recent capital additions, including 27 new wind turbines at the Langdon Wind Energy Center.

Table of Contents

Plastics

(in thousands)	Three Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 36,690	$ 36,975	$ (285)	(0.8)
Cost of Goods Sold	32,189	31,909	280	0.9
Operating Expenses	672	1,782	(1,110)	(62.3)
Depreciation and Amortization	733	769	(36)	(4.7)
Operating Income	$ 3,096	$ 2,515	$ 581	23.1

Operating revenues for the plastics segment decreased as result of a 10.9% decrease in pounds of pipe sold, mostly offset by an 11.4% increase in the price per pound of pipe sold. The increase in cost of goods sold reflects a 15.6% increase in resin prices per pound of pipe sold. The decrease in operating expenses reflects a decrease in bonus incentives directly related to decreased sales and profits in the nine months ended September 30, 2008 compared with the nine months ended September 30, 2007.

Manufacturing

(in thousands)	Three Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 127,778	$ 95,330	$ 32,448	34.0
Cost of Goods Sold	105,965	75,236	30,729	40.8
Operating Expenses	12,725	8,800	3,925	44.6
Plant Closure Costs	883		883	
Depreciation and Amortization	5,146	3,341	1,805	54.0
Operating Income	$ 3,059	$ 7,953	$ (4,894)	(61.5)

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

Revenues at DMI Industries, Inc. (DMI) increased $17.0 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 $12.7 million, including $6.7 million from Miller Welding & Iron Works, Inc. (Miller Welding), acquired in May 2008. BTD s revenue increased $4.0 million as a result of increased product sales to existing customers and $2.0 million as a result of increased prices mainly related to higher raw material costs.

Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $1.6 million as a result of increased sales of horticultural products.

Revenues at ShoreMaster, Inc. (ShoreMaster) increased $1.2 million as a result of a $3.3 million increase in commercial sales, including revenue earned on a large marina project in Costa Rica in the third quarter of 2008, partially offset by a $2.1 million increase in dealer sales incentive discounts.

Table of Contents

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

DMI s cost of goods sold increased $17.2 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 have been higher than expected and production has not reached levels necessary to cover these costs. Included in cost of goods sold for the three months ended September 30, 2008 are costs of $1.5 million associated with start-up inefficiencies at the Oklahoma plant. Higher freight costs and steel surcharges have also resulted in increased material costs. Increased gross profits in West Fargo were offset by higher costs for overhead items like rentals and shop supplies.

Cost of goods sold at BTD increased $8.6 million, mainly in the categories of material and labor costs, as a result of increased sales volumes and higher material prices. Miller Welding accounted for $4.9 million of the $8.6 million increase in cost of goods sold, including $0.3 million in fair valuation write-ups of acquired inventory that was sold in the third 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 $1.5 million, mainly in material costs related to increased sales of horticultural products.

Cost of goods sold at ShoreMaster increased $3.5 million as a result of increased material costs related to commercial projects, including costs incurred on a large marina project in Costa Rica in the third quarter of 2008 scheduled for completion in December 2008.

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

Operating expenses at DMI increased $2.0 million, mainly for labor, benefit and contracted services, including expenses 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 $1.9 million as a result of increases in labor and benefit expenses and software maintenance costs. Third quarter 2008 operating expenses at Miller Welding, acquired in May 2008, were $0.4 million.

T.O. Plastics operating expenses increased $0.1 million between the quarters.

ShoreMaster s operating expenses decreased $0.1 million between the quarters, excluding the $0.9 million in plant closure costs incurred in the third quarter of 2008.

The $0.9 million in plant closure costs in the third quarter of 2008 is mainly losses and expenses related to the shutdown and sale 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.

Table of Contents

Health Services

(in thousands)	Three Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 31,139	$ 31,360	$ (221)	(0.7)
Cost of Goods Sold	24,779	24,193	586	2.4
Operating Expenses	4,726	5,816	(1,090)	(18.7)
Depreciation and Amortization	1,020	1,003	17	1.7
Operating Income	$ 614	$ 348	$ 266	76.4

Revenues from scanning and other related services were down $0.1 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 were also down $0.1 million between the quarters. The increase in cost of goods sold is mainly due to increases in repair and maintenance and other equipment operating costs on the imaging side of the business. The decrease in operating expenses includes a $0.6 million gain on the sale of a portable imaging business in Wisconsin in the third quarter of 2008 and a $0.4 million decrease in sales and marketing expenses between the quarters.

Food Ingredient Processing

(in thousands)	Three Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 15,333	$ 15,714	$ (381)	(2.4)
Cost of Goods Sold	15,380	11,926	3,454	29.0
Operating Expenses	540	792	(252)	(31.8)
Depreciation and Amortization	1,057	1,017	40	3.9
Operating (Loss) Income	$ (1,644)	$ 1,979	$ (3,623)	(183.1)

The decrease in revenues in the food ingredient processing segment is due to a 4.8% decrease in pounds of product sold, partially offset by a 2.5% increase in the price per pound of product sold. Lower production caused by potato supply shortages at the end of the 2007 crop and a late harvest of the 2008 crop increased overhead costs per unit of sales. These supply constraints, combined with energy costs rising at rates faster than could be passed through to customers, increased costs and lowered profits on products sold in the third quarter of 2008. The decrease in operating expenses reflects a decrease in bonus incentives directly related to decreased sales and gross margins in 2008 compared with 2007. The increase in depreciation and amortization expense between the quarters is due to recent capital additions.

Table of Contents

Other Business Operations

(in thousands)	Three Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 59,650	$ 51,231	$ 8,419	16.4
Cost of Goods Sold	36,221	37,029	(808)	(2.2)
Operating Expenses	15,194	11,108	4,086	36.8
Depreciation and Amortization	609	512	97	18.9
Operating Income	$ 7,626	$ 2,582	$ 5,044	195.4

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 Midwest Construction Services, Inc. (MCS) decreased $3.2 million as a result of a reduction in jobs in progress between the quarters. In the third quarter of 2007, MCS was working on three major wind farm projects compared with two major projects in the third quarter of 2008.

Revenues at E.W. Wylie Corporation (Wylie) increased $4.6 million as a result of the impact of increased fuel costs on shipping rates, but also as a result of a 2.4% increase in combined miles driven by company-owned and owner-operated trucks and higher revenues from heavy-haul services introduced in the fourth quarter of 2007 and the transport of wind towers starting in 2008. Miles driven by company-owned trucks increased 20.3% as a result of the addition of heavy haul and wind tower transport services. Miles driven by owner-operated trucks decreased 31.6% between the quarters.

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

Foley Company s cost of goods sold increased $6.2 million, including increases of $2.3 million in subcontractor costs, $2.0 million in material costs and $1.8 million in labor and benefit costs as a result of increased construction activity and jobs in progress.

Cost of goods sold at MCS decreased $7.0 million due to decreases in material and subcontractor costs directly related to MCS having fewer jobs in progress between the quarters.

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

Wylie s operating expenses increased $3.3 million between the quarters. Fuel costs increased $2.6 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 $0.5 million and equipment rental costs increased by $0.3 million due to the addition of heavy-haul services in the fourth quarter of 2007. Subcontractor expenses decreased $0.2 million as a result of the decrease in miles driven by owner-operated trucks.

MCS s operating expenses increased $0.5 million between the quarters due to increases in salary and benefit expenses.

Foley Company s operating expenses increased $0.3 million between the quarters mostly due to increased salary and benefit costs.

Depreciation expense increases are the result of recent capital additions at all three companies.

Table of Contents

Corporate

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

	Three Months Ended September 30,			%
(in thousands)	2008	2007	Change	Change
Operating Expenses	$3,384	$1,973	$1,411	71.5
Depreciation and Amortization	134	143	(9)	(6.3)

The change in corporate operating expenses includes increases in stock-based compensation, benefit expenses, software licensing and maintenance expenses and increases in outside professional service costs related to the formation of a holding company.

Interest Charges

Interest charges increased $2.3 million in the third quarter of 2008 compared with the third 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 $0.5 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 third quarter of 2008 compared with the third quarter of 2007. The electric utility recorded no allowance for equity funds used in construction in the third 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 $3.9 million (49.4%) decrease in income taxes between the quarters is primarily due to a $7.6 million (35.8%) decrease in income before income taxes for the three months ended September 30, 2008 compared with the three months ended September 30, 2007. Federal production tax credits of $0.6 million and North Dakota wind tax credits of $0.1 million recorded in the third quarter of 2008 related to the electric utility s new wind turbines also contributed to the reduction in taxes between the quarters. Also, the allowance for equity funds used during construction at the electric utility is not subject to income tax expense.

Table of Contents

Comparison of the Nine Months Ended September 30, 2008 and 2007

Consolidated operating revenues were $976.8 million for the nine months ended September 30, 2008 compared with $909.2 million for the nine months ended September 30, 2007. Operating income was $47.1 million for the nine months ended September 30, 2008 compared with $76.6 million for the nine months ended September 30, 2007. The Company recorded diluted earnings per share of $0.69 for the nine months ended September 30, 2008 compared to $1.31 for the nine months ended September 30, 2007.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the nine-month periods ended September 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)	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Operating Revenues:		
Electric	$ 235	$ 259
Nonelectric	1,676	1,214
Cost of Goods Sold	1,600	1,187
Other Nonelectric Expenses	311	286

Electric

(in thousands)	Nine Months Ended September 30, 2008	2007	Change	% Change
Retail Sales Revenues	$ 209,228	$ 196,573	$ 12,655	6.4
Wholesale Revenues	19,681	17,687	1,994	11.3
Net Marked-to-Market Gain	2,284	2,647	(363)	(13.7)
Other Revenues	17,946	15,755	2,191	13.9
Total Operating Revenues	$ 249,139	$ 232,662	$ 16,477	7.1
Production Fuel	53,444	47,496	5,948	12.5
Purchased Power System Use	39,598	43,531	(3,933)	(9.0)
Other Operation and Maintenance Expenses	87,591	80,738	6,853	8.5
Depreciation and Amortization	23,378	19,501	3,877	19.9
Property Taxes	7,414	7,591	(177)	(2.3)
Operating Income	$ 37,714	$ 33,805	$ 3,909	11.6

The increase in retail revenues reflects $5.5 million in Minnesota and North Dakota Renewable Resource Cost Recovery Rider revenue. In the third quarter of 2008, the electric utility billed and accrued $3.1 million in Minnesota Renewable Resource Cost Recovery Rider revenue for recovery of the Minnesota portion of the electric utility s renewable energy expenses and investment costs going back to January 1, 2008 as a result of the MPUC s August 2008 approval of the electric utility s request for a Renewable Resource Cost Recovery Rider. The increase in retail revenues also includes $2.6 million attributable to an increase in Minnesota retail electric rates of approximately 2.9%, which was approved by the MPUC. The remaining $4.6 million increase in retail revenues was due to a 2.8% increase in retail kwh sales resulting from colder weather in the first six months of 2008, when heating degree days were 11.4%

higher than in the first six months of 2007.

Wholesale electric revenues from company-owned generation were $18.2 million for the nine months ended September 30, 2008 compared with $15.2 million for the nine months ended September 30, 2007. The increase reflects a 25.9% increase in wholesale kwh sales, partially offset by a 5.1% reduction in the price per kwh sold. A 5.3% 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 nine months of 2008 were $1.5 million compared with $2.5 million in the first nine months of 2007. Trading volumes were higher but profit margins on trades were significantly lower between the periods. Trading volumes were up 42.8% but profit margins on trades decreased 88% between the periods. Net revenue from the purchase and sale of Financial Transmission Rights increased $1.9 million between the quarters.

The $0.4 million decrease in net marked-to-market gains on forward energy contracts reflects lower margins on trades in the first nine months of 2008 compared with the first nine months of 2007.

Construction work performed for other entities on regional wind power projects contributed $1.7 million to the increase in other electric revenues. MISO tariff revenues increased $0.4 million between the periods.

The increase in fuel costs reflects a 10.4% increase in the cost of fuel per kwh generated combined with a 1.9% increase in kwhs generated at fuel-burning plants. 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 3.2% of total kwh generation in the first nine months of 2008.

The decrease in purchased power system use is due to a 12.8% reduction in kwhs purchased partially offset by a 4.3% 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.

The increase in other operating and maintenance expenses between the periods includes: (1) $2.0 million for Hoot Lake unit 2 turbine repairs and boiler maintenance in 2008, (2) a $1.6 million increase in costs related to contracted construction work completed for other entities on regional wind projects, (3) $0.8 million in increased wage and benefit expenses, (4) $0.8 million for boiler washes at Big Stone Plant and Coyote Station in 2008, (5) $0.4 million in expenses associated with the Langdon Wind Center operating and maintenance agreement, (6) a $0.4 million increase in storm repair and tree-trimming expenses, (7) a $0.3 million increase in software licensing expenses, (8) a $0.2 million increase in bad debt expenses, and (9) a $0.2 million increase in Big Stone Plant legal costs.

Depreciation expenses increased as a result of recent capital additions, including 27 new wind turbines at the Langdon Wind Energy Center.

Table of Contents

Plastics

(in thousands)	Nine Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 99,685	$ 114,319	$ (14,634)	(12.8)
Cost of Goods Sold	87,810	93,564	(5,754)	(6.1)
Operating Expenses	3,939	5,074	(1,135)	(22.4)
Depreciation and Amortization	2,251	2,298	(47)	(2.0)
Operating Income	$ 5,685	$ 13,383	$ (7,698)	(57.5)

Operating revenues for the plastics segment decreased mainly as result of a 17.8% decrease in pounds of pipe sold, partially offset by a 6.2% 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 14.2% due to higher resin prices, resulting in a 30.2% decline in gross margins per pound of pipe sold. The decrease in operating expenses reflects a decrease in bonus incentives directly related to decreased sales and profits in the nine months ended September 30, 2008 compared with the nine months ended September 30, 2007.

Manufacturing

(in thousands)	Nine Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 345,715	$ 286,341	$ 59,374	20.7
Cost of Goods Sold	288,190	225,670	62,520	27.7
Operating Expenses	33,261	25,839	7,422	28.7
Plant Closure Costs	2,295		2,295	
Depreciation and Amortization	13,771	9,734	4,037	41.5
Operating Income	$ 8,198	$ 25,098	$ (16,900)	(67.3)

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

Revenues at DMI increased $36.6 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 $21.2 million, including $10.9 million 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 $4.7 million as a result of increased sales of horticultural products.

Revenues at ShoreMaster decreased $3.2 million between the periods, of which $1.7 million related to a major marina project in California that was underway throughout 2007 and completed in early April 2008. Reduced sales of commercial products in Missouri as a result of new permitting processes on Lake of the Ozarks also contributed to the decrease in revenues. Also, sales in Missouri in 2007 benefitted from a November 2006 storm on Lake of the Ozarks.

Table of Contents

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

DMI s cost of goods sold increased $41.0 million as a result of increases in production and sales activity, including initial operations at its new plant in Oklahoma. DMI experienced a $4.3 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 have been higher than expected and production has not reached levels necessary to cover these costs. Included in cost of goods sold for the nine months ended September 30, 2008 are costs of $4.3 million associated with start-up inefficiencies at the Oklahoma plant 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 $15.4 million, mainly in the categories of materials, labor and shop supply costs, as a result of increased sales volumes and higher material prices. Miller Welding accounted for $8.3 million of the $15.4 million increase in cost of goods sold, including $1.0 million in fair valuation write-ups of acquired inventory that was sold in the second and third quarters of 2008. Under business combination accounting rules, acquired inventory is written up to fair value.

Cost of goods sold at T.O. Plastics increased $3.9 million, mainly in material costs related to increased sales of horticultural products.

Cost of goods sold at ShoreMaster increased $2.3 million as a result of increased material costs related to residential products sold in 2008 and costs incurred in 2008 related to the construction of a large marina project in Costa Rica scheduled for completion in December 2008, offset by reductions in cost of goods sold in Missouri related to reduced commercial sales on Lake of the Ozarks.

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

Operating expenses at DMI increased $3.9 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 $3.0 million mainly as a result of increases in labor, benefit and contracted service expenses and the May 2008 acquisition of Miller Welding.

ShoreMaster s operating expenses increased $0.4 million, excluding the $2.3 million in plant closure costs incurred in 2008, as a result of increases in sales and marketing salaries and expenses.

T.O. Plastics operating expenses increased $0.1 million between the periods.

The $2.3 million in plant closure costs in 2008 includes employee-related termination obligations, asset impairment costs and other losses and expenses incurred related to the shutdown and sale 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.

Table of Contents

Health Services

(in thousands)	Nine Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 91,144	$ 96,775	$ (5,631)	(5.8)
Cost of Goods Sold	72,198	72,425	(227)	(0.3)
Operating Expenses	16,185	17,733	(1,548)	(8.7)
Depreciation and Amortization	3,015	2,986	29	1.0
Operating (Loss) Income	$ (254)	$ 3,631	$ (3,885)	(107.0)

Revenues from scanning and other related services were down $4.0 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 $1.6 million between the periods, reflecting a trend away from distributor sales in favor of commission based manufacturer representative sales. Decreases in cost of goods sold related to the decrease in equipment sales revenue were mostly offset by increases in repair and maintenance and other equipment operating costs on the imaging side of the business. The decrease in operating expenses includes a $0.6 million gain on the sale of a portable imaging business in Wisconsin in the third quarter of 2008 and a $0.9 million decrease in sales and marketing expenses between the periods.

Food Ingredient Processing

(in thousands)	Nine Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 47,144	$ 53,612	$ (6,468)	(12.1)
Cost of Goods Sold	40,416	43,229	(2,813)	(6.5)
Operating Expenses	2,181	2,334	(153)	(6.6)
Depreciation and Amortization	3,201	2,985	216	7.2
Operating Income	$ 1,346	$ 5,064	$ (3,718)	(73.4)

The decrease in revenues in the food ingredient processing segment is due to an 18.1% decrease in pounds of product sold, partially offset by a 7.4% 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 14.1% 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 and due to lower production caused by potato supply shortages at the end of the 2007 crop and a late harvest of the 2008 crop. 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 higher fuel oil and natural gas prices and production decreases related to potato supply shortages which resulted in higher overhead absorption costs in the third quarter of 2008. The decrease in operating expenses reflects a decrease in bonus incentives directly related to decreased sales and gross margins in 2008 compared with 2007. The increase in depreciation and amortization expense between the periods is due to recent capital additions.

Table of Contents

Other Business Operations

(in thousands)	Nine Months Ended September 30, 2008	2007	Change	% Change
Operating Revenues	$ 145,840	$ 126,964	$ 18,876	14.9
Cost of Goods Sold	96,443	87,799	8,644	9.8
Operating Expenses	41,260	32,700	8,560	26.2
Depreciation and Amortization	1,567	1,466	101	6.9
Operating Income	$ 6,570	$ 4,999	$ 1,571	31.4

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

Revenues at Foley Company increased $14.0 million due to higher backlog going into 2008 resulting in an increase in volume of jobs in progress.

Revenues at MCS decreased $1.4 million as a result of a reduction in the number of jobs in progress in 2008 compared to 2007 in the area of electrical infrastructure for delivery of wind generated electricity.

Revenues at Wylie increased $6.3 million mainly as a result of the impact of increased fuel costs on shipping rates. Miles driven by company-owned trucks increased 22.9% as a result of the addition of heavy haul and wind tower transport services. Miles driven by owner-operated trucks decreased 37.5%. Combined miles driven by company-owned and owner-operated trucks increased 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 $12.5 million, including increases of $8.4 million in subcontractor and material costs and $4.0 million in direct labor and benefit costs, as a result of increased construction activity and jobs in progress.

Cost of goods sold at MCS decreased $3.9 million between the periods due to decreases in material and subcontractor costs directly related to MCS having fewer jobs in progress.

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

Wylie s operating expenses increased $5.7 million between the periods. Fuel costs increased $6.0 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 $1.1 million and equipment rental costs increased by $0.5 million due to the addition of heavy-haul services in the fourth quarter of 2007. Travel expenses increased $0.3 million. Subcontractor expenses decreased $2.2 million as a result of the decrease in miles driven by owner-operated trucks.

MCS s operating expenses increased $1.8 million between the periods due to increases in salary, benefit and contracted services expenses.

Foley Company s operating expenses increased $0.7 million between the periods due to increases in labor and insurance costs.

Operating expenses at Otter Tail Energy Services Company increased $0.4 million between the periods related to the investigation and development of renewable energy wind-generation projects.

Table of Contents

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.

	Nine Months Ended September 30,			%
(in thousands)	2008	2007	Change	Change
Operating Expenses	$11,696	$8,952	$2,744	30.7
Depreciation and Amortization	417	436	(19)	(4.4)

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, increases in claim loss provisions at our captive insurance company and increases in software licensing and maintenance expenses. Corporate expenses in 2007 included a $0.6 million gain on disposal of assets.

Interest Charges

Interest charges increased $6.2 million in the first nine months of 2008 compared with the first nine 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 $1.5 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 nine months of 2008 compared with the first nine months of 2007. The electric utility recorded no allowance for equity funds used in construction in the first nine 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 $15.7 million (67.7%) decrease in income taxes between the periods is primarily the result of a $34.1 million (54.2%) decrease in income before income taxes for the nine months ended September 30, 2008 compared with the nine months ended September 30, 2007. Federal production tax credits of $1.9 million and North Dakota wind tax credits of $0.2 million recorded in the first nine months of 2008 related to the electric utility s new wind turbines also contributed to the reduction in taxes between the periods. Also, the allowance for equity funds used during construction at the electric utility is not subject to income tax expense.

Table of Contents

2008 EXPECTATIONS

The statements in this section are based on our current outlook for 2008 and are subject to risks and uncertainties given current global economic conditions and the other risk factors outlined under Forward Looking Information Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995.

We have revised our 2008 earnings guidance to be in a range of $1.05 to $1.30 per diluted share from our previously announced range of $1.25 to $1.50. Contributing to the revised earnings guidance for 2008 are the following items:

- We continue to expect increased levels of net income from our electric segment in 2008, but to a lesser degree due to milder weather conditions in the third quarter and early fourth quarter, an unscheduled outage at Hoot Lake Plant Unit 2 late in the third quarter and the impact of lower forward energy prices on asset-based wholesale margins. The increase is attributable to the 2.9% rate increase granted in Minnesota and rate riders for wind energy in North Dakota and Minnesota. The increase also results from having lower-cost generation available for the year, as there have been no major shutdowns of 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. Also, announced reductions in polyvinyl chloride (PVC) resin prices in October 2008 are expected to negatively impact PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory. Announced capacity expansions are not expected to have a material impact on 2008 results.
- We expect a further 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, for ShoreMaster the continuing impact of a softening economy on its residential business and limited access to credit markets for customers to finance construction of commercial projects is expected to cause a further decrease in net income for our manufacturing segment in 2008. Backlog in place on September 30, 2008 in our manufacturing segment to support revenues for the remainder of 2008 is approximately $131 million. This compares with $95 million in revenue earned in the fourth quarter of 2007. DMI accounts for a substantial portion of the 2008 backlog.
- We expect a further decline in net income from our health services segment in 2008 due to lower utilization levels of certain imaging assets and cancellation of equipment orders by hospitals that were expected to occur in 2008 but have been either completely cancelled or delayed into 2009 due to concerns over the weakening economy and limited access to credit markets to finance equipment purchases.
- We expect a significant reduction in net income from our food ingredient processing business in 2008 as a result of higher natural gas and fuel oil prices during the first three quarters and reductions in raw potato supplies which are expected to lower sales volumes for the rest of 2008.
- 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 third quarter of 2008 was approximately $48 million for the remainder of 2008 compared with $51 million in revenue in the fourth quarter of 2007.
- We expect corporate general and administrative costs to increase in 2008.

Table of Contents
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, to reduce borrowings under our lines of credit, including borrowings used to finance DMI s plant addition in Oklahoma 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, especially given the current disruptions in global financial markets, 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 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. Contracts related to construction of the 32 wind towers and turbines to be owned by Otter Tail Power Company increased our 2008 purchase obligations by $121 million.
In September 2008, we completed a public offering of 5,175,000 common shares under our universal shelf registration statement filed with the Securities and Exchange Commission, including 675,000 common shares issued pursuant to the full exercise of the underwriters overallotment option. The public offering price was $30 per share. Net proceeds from the sale of the common shares after deducting underwriting discounts and commissions and offering expenses were $149.1 million. The net proceeds will be used to finance the construction of Otter Tail Power Company s 32 wind turbines and collector system at the Ashtabula Wind Center in Barnes County, North Dakota and the expansion of DMI s wind tower manufacturing facilities in Tulsa, Oklahoma and West Fargo, North Dakota.
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 1.75%, 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 September 30, 2008, $112.0 million of the $200 million line of credit was in use and $15.0 million was restricted from use to cover outstanding letters of credit.
On July 30, 2008 Otter Tail Corporation, dba Otter Tail Power Company replaced its credit agreement with U.S. Bank National Association, which provided for a $75 million line of credit, with a new credit agreement providing

for a $170 million line of credit with an accordion feature whereby the line can be increased to $250 million as described in the new credit agreement. The 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 0.5%, subject to adjustment based on the ratings of the Company s senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement is subject to renewal on July 30, 2011. As of September 30, 2008, no amounts were borrowed under this line of credit.

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, the Lombard US Equipment Finance note and the financial guaranty insurance policy with Ambac Assurance Corporation relating to our pollution control refunding bonds contain covenants by us 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 September 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 securities ratings at September 30, 2008 were:

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

On September 26, 2008 Standard and Poor s Ratings Services lowered its corporate credit rating and senior unsecured debt rating on the Company from BBB+ to BBB- and changed its outlook from negative to stable, citing a growing appetite for non-utility businesses in combination with expected credit measures that are more consistent with the BBB- rating and expected cash flow constraints given current economic indicators. Our disclosure of these securities ratings is not a recommendation to buy, sell or hold our securities. This and any future downgrade in our securities ratings 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 $90.9 million have been sold in 2008. Discounts of $0.5 million for the nine months ended September 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 September 30, 2008 was $22.7 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 $3.5 million on September 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 $40.2 million for the nine months ended September 30, 2008 compared with cash provided by operating activities of $57.3 million for the nine months ended September 30, 2007. The $17.1 million decrease in cash from operating activities includes an $18.5 million decrease in net income, and a $9.4 million increase in cash used for working capital items from $26.3 million in the first nine months of 2007 to $35.7 million in the first nine months of 2008, offset by an $8.2 million increase in noncash depreciation expense and a $2.0 million reduction in discretionary cash contributions to our pension fund.

Major uses of funds for working capital items in the first nine months of 2008 were an increase in receivables of $24.3 million, an increase in inventories of $9.1 million and an increase in other current assets of $8.2 million, partially offset by an increase in payables and other current liabilities of $5.0 million. The $24.3 million increase in receivables includes: (1) $14.4 million at the electric utility as a result of increases in wholesale sales and energy trading volumes in 2008, higher energy bills related to recently approved resource recovery riders and billings for increased levels of contracted construction work for other entities, and (2) $9.4 million at Foley Company related to an increase in the number and size of jobs in progress in 2008. The $9.1 million increase in inventories is mainly related to a buildup of inventory at our plastic pipe companies as a result of recent declines in sales combined with

Table of Contents

the effect of higher PVC resin prices on raw material and finished goods inventory. The $8.2 million increase in other current assets includes: (1) an $18.4 million increase in costs in excess of billings, mainly at DMI, as a result of increased production activity, (2) a $4.3 million increase in prepaid expenses across all companies related to the timing of 2008 annual insurance premiums and other payments, and (3) a $3.9 million increase in income taxes receivable, offset by (4) an $18.3 million decrease in accrued utility revenues related to a decrease in unbilled revenue due to milder weather in September 2008 compared to December 2007. The $5.0 million increase in payables and other current liabilities is mainly due to a $4.5 million increase in accounts payable and billings in excess of costs at Foley Company related to increased levels of jobs in progress.

Net cash used in investing activities was $206.9 million for the nine months ended September 30, 2008 compared with $103.7 million for the nine months ended September 30, 2007. Cash used for capital expenditures increased by $72.8 million between the periods. Cash used for capital expenditures at the electric utility increased by $67.6 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 $3.0 million related to the installation of a new PVC pipe extrusion line at their Hampton, Iowa plant. Cash used for capital expenditures increased by $2.3 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. We completed two acquisitions during the first nine months of 2007 for a combined purchase price of $6.8 million.

Net cash provided by financing activities was $144.2 million for the nine months ended September 30, 2008 compared with $43.0 million for the nine months ended September 30, 2007. Proceeds from the issuance of common stock, net of issuance expenses, were $156.8 million in the first nine months of 2008 compared with $7.6 million in the first nine months of 2007. We issued 5,175,000 common shares in a public offering in September 2008. During the first nine months of 2008, 276,535 common shares were issued for stock options exercised compared with 293,382 common shares issued for stock options exercised in the first nine months of 2007. Proceeds from the issuance of long-term debt were $1.1 million in the first nine months of 2008 compared with $25.1 million in the first nine months of 2007. Proceeds from short-term borrowings were $17.0 million in the first nine months of 2008 compared with proceeds from short-term borrowings of $39.9 million in the first nine months of 2007. Dividends paid on common and preferred shares in the first nine months of 2008 were $27.4 million compared with $26.6 million in the first nine months of 2007. The increase in dividend payments is due to a 1.5 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.

Table of Contents

In August 2008, IPH entered into contracts with its natural gas suppliers for the firm purchase of natural gas to cover portions of its anticipated natural gas needs in Ririe, Idaho and Center, Colorado from September 2008 through August 2009 at fixed prices. Commitments under these contracts are contractual obligations.

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: (1) $121 million in 2008 for construction of 48 megawatts of wind energy generation at the Ashtabula Wind Center site in Barnes County, North Dakota and, (2) $1.1 million in 2008 and $1.3 million in 2009 related to IPH s firm commitments for the purchase of natural gas.

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

Critical Accounting Policies Involving Significant Estimates

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

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

Table of Contents

Actions by the regulators of our 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.
A sustained decline in our common stock price below book value may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as credit facility covenants.
The terms of some of our contracts could expose us to unforeseen costs and costs not within our control, which may not be recoverable and could adversely affect our results of operations and financial condition.
We are subject to risks associated with energy markets.
Future operating results of our electric segment will be impacted by the outcome of rate rider filings in Minnesota for transmission 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.
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 $10.8 million in costs related to the planned construction of a second electric generating unit at its Big Stone Plant site as of September 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, a portion of 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 the corporation to incur substantial capital expenditures and 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 (CO2) emission levels or taxes on CO2 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, 2009. Should this tax credit not be renewed, the revenues and earnings of this business and the electrical contracting business in our other business operations segment could be reduced.
If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.

Table of Contents

Our plans to grow and diversify through acquisitions and capital projects may not be successful and could result in poor financial performance.
Our plans to acquire, grow and operate our nonelectric businesses could be limited by state law.
Competition is a factor in all of our businesses.
Economic conditions could have a negative impact on our businesses. Tightening of credit in financial markets, a decline in the level of economic activity and uncertainty regarding energy and commodity prices could adversely affect our results of operations and our future growth.
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. Disruptions, uncertainty or volatility in the financial markets can also adversely impact our results of operations, the ability of customers to finance purchases of goods and services, and our financial condition as well as exert downward pressure on stock prices and/or limit our ability to sustain our current common stock dividend level.
As of September 30, 2008, our defined benefit pension plan assets have declined significantly since December 31, 2007. At this time, we are unable to predict the plan s asset values and required valuation parameters. We will measure our plan s asset values and pension benefit obligations and calculate our 2009 pension benefit expense and 2009 annual plan contribution requirements at December 31, 2008.
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 dealership arrangements with Philips Medical which are scheduled to expire on December 31, 2008.
Technological change in the diagnostic imaging industry could reduce the demand for diagnostic imaging services and require our health services operations to incur significant costs to upgrade their equipment.
Actions by regulators of our health services operations 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 our construction businesses could lead to adverse financial results.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At September 30, 2008 we had exposure to market risk associated with interest rates because we had $112.0 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.75% under the Varistar Credit agreement. At September 30, 2008 we had limited exposure to changes in foreign currency exchange. 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 26% of IPH sales in the first nine months of 2008 were outside the United States and the Canadian operations of IPH pays its operating expenses in Canadian dollars. However, IPH s Canadian subsidiary has locked in exchange rates for the exchange of U.S. dollars for Canadian Dollars for approximately 100% of its cash needs through December 31, 2008 and approximately 50% of its cash needs for the period January 1, 2009 through July 31, 2009 by entering into forward foreign currency exchange contracts. On September 30, 2008 IPH s Canadian subsidiary held contracts for the exchange of $5.2 million USD for $5.4 million CAD. 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 September 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 September 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 September 30, 2008 the electric utility had recognized, on a pretax basis, $1,084,000 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

Table of Contents

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 September 30, 2008, 99.7% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $17,000 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 September 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 September 30, 2008 and the change in our consolidated balance sheet position from December 31, 2007 to September 30, 2008:

(in thousands)	September 30, 2008
Current Asset Marked-to-Market Gain	$ 4,922
Regulatory Asset Deferred Marked-to-Market Loss	271
Total Assets	5,193
Current Liability Marked-to-Market Loss	(3,427)
Regulatory Liability Deferred Marked-to-Market Gain	(682)
Total Liabilities	(4,109)
Net Fair Value of Marked-to-Market Energy Contracts	$ 1,084

(in thousands)	Year-to-Date September 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	570
Net Fair Value of Contracts Entered into in 2007 at End of Period	998
Changes in Fair Value of Open Contracts Entered into in 2008	86
Net Fair Value End of Period	$ 1,084

The $1,084,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market on September 30, 2008 is expected to be realized on settlement as scheduled in October and November of 2008.

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 September 30, 2008 was \$5.4 million. As of September 30, 2008 we had a net credit risk exposure of \$13.9 million from twelve counterparties with investment grade credit ratings. We had no exposure at September 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).

Table of Contents

The $13.9 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 September 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.

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

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH s Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in March 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 the contract, for a total exchange of $3,600,000 USD for $3,695,280 CAD. Three of these contracts were outstanding as of September 30, 2008.

In July 2008, IPH s Canadian subsidiary entered into additional forward contracts for the exchange of U.S. dollars into Canadian dollars to cover approximately 50% of its monthly expenditures for the twelve-month period of August 2008 through July 2009. Each contract is for the exchange of $400,000 USD for the amount of Canadian dollars stated in the contract, for a total exchange of $4,800,000 USD for $5,003,160 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 September 30, 2008 were valued and marked to market on September 30, 2008 based on quoted exchange values of similar contracts that could be purchased on September 30, 2008. Based on those values, IPH s Canadian subsidiary recorded a derivative liability of $114,000 as of September 30, 2008 and net mark-to-market losses of $106,000 in 2008.

Table of Contents

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 September 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 September 30, 2008.

During the fiscal quarter ended September 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.

On September 9, 2008, Renewable Energy System Americas, Inc. (RES), a developer of wind generation and PEAK Wind Development, LLC (PEAK Wind), a group of landowners in Barnes County, North Dakota, filed a complaint with FERC alleging that the electric utility and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act, (FPA) to deny RES/PEAK Wind access to the Pillsbury Line, an interconnection line that Minnkota is building with the electric utility as its contractor, to interconnect generation projects being developed by the electric utility and FPL Energy, Inc. RES/PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) that FERC direct MISO, to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that the electric utility, Minnkota and FPL Energy pay any costs associated with interconnecting the Glacier Ridge Project to the MISO transmission system which would result from the interconnection of the Pillsbury Line to the Minnkota transmission system, and that FERC assess civil penalties against the electric utility. The electric utility answered the Complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that FERC dismiss the Complaint. On October 14, 2008, RES and PEAK Wind filed an Answer to the electric utility s Answer and, restated the allegations included in the initial Complaint. RES and PEAK Wind also added a request that FERC rescind both the electric utility s waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, the electric utility filed a Reply, denying the allegations made by RES and PEAK Wind in its Answer. The Company believes the claims that the electric utility has violated the FPA are without merit. The ultimate outcome of this matter cannot be determined at this time.

Table of Contents

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

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

Any forward-looking statement described below or elsewhere in this Quarterly Report on Form 10-Q or our other filings with the Securities and Exchange Commission speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of the factors, nor can we assess the effect of each factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The following factors and the other matters discussed herein are important factors that could cause actual results or outcomes to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

GENERAL

Federal and state environmental regulation could require us to incur substantial capital expenditures and increased operating costs.

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

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

Table of Contents

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

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

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

Changes in the U.S. capital markets could also have significant effects on our pension plan. Our pension income or expense is affected by factors including the market performance of the assets in the master pension trust maintained for the pension plans for some of our employees, the weighted average asset allocation and long-term rate of return of our pension plan assets, the discount rate used to determine the service and interest cost components of our net periodic pension cost and assumed rates of increase in our employees future compensation. If our pension plan assets do not achieve positive rates of return, or if our estimates and assumed rates are not accurate, our earnings may decrease because net periodic pension costs would rise and we could be required to provide additional funds to cover our obligations to employees under the pension plan. As of September 30, 2008, our defined benefit pension plan assets have declined significantly since December 31, 2007. At this time, we are unable to predict the plan s asset values and required valuation parameters. We will measure our plan s asset values and pension benefit obligations and calculate our 2009 pension benefit expense and 2009 annual plan contribution requirements at December 31, 2008.

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

We had approximately $106.8 million of goodwill recorded on our consolidated balance sheet as of September 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.

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

Table of Contents

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

Economic conditions could negatively impact our businesses.

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

If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.

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

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

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

Our plans to acquire, grow and operate our non-electric businesses could be limited by state law.

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

The terms of some of our contracts could expose us to unforeseen costs and costs not within our control, which may not be recoverable and could adversely affect our results of operations and financial condition.

DMI and ShoreMaster, two businesses in our manufacturing segment, and our construction companies frequently provide products and services pursuant to fixed-price contracts. Revenues recognized on jobs in progress under fixed-price contracts for the year ended December 31, 2007 were $325 million. Under those contracts, we agree to perform the contract for a fixed price and, as a result, can improve our expected profit by superior contract performance, productivity, worker safety and other factors resulting in cost savings. However, we could incur cost overruns above the approved contract price, which may not be recoverable.

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

We are subject to risks associated with energy markets.

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

ELECTRIC

We may experience fluctuations in revenues and expenses related to our electric operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to shareholders or scheduled payments on our debt obligations.

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

As of September 30, 2008 the electric utility has capitalized $10.8 million in costs related to the planned construction of a second electric generating unit at our Big Stone Plant site. 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, a portion of these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable. Additionally, if we are unable to complete the construction of Big Stone II and commence operations, we may be forced to purchase power in order to meet customer needs. There is no guarantee that in such a case we would be able to obtain sufficient supplies of power at reasonable costs. If we are forced to pay higher than normal prices for power, the increase in costs could reduce our earnings if we were not able to recover the increased costs from our electric customers through the FCA.

Table of Contents

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

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

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. Recovery of MISO schedule 16 and 17 administrative costs associated with providing electric service to North Dakota customers are currently being deferred pending the results of our general rate case in North Dakota filed in November 2008. If we are not granted recovery of the $0.8 million in deferred costs as of September 30, 2008 we could be required to recognize these costs immediately in expense at the time recovery is denied.

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

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

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

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

Changes to regulation of generating plant emissions, including but not limited to CO_2 emissions, could affect our operating costs and the costs of supplying electricity to our customers.

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 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.

PLASTICS

Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of PVC resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for our plastics business.

We rely on a limited number of vendors to supply the PVC resin used in our plastics business. Two vendors accounted for approximately 93% of our total purchases of PVC resin in the first nine months of 2008, approximately 95% of our total purchases of PVC resin in 2007 and approximately 99% of our total purchases of PVC resin in 2006. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of U.S. resin production plants are located in the Gulf Coast region, which may increase the risk of a shortage of resin in the event of a hurricane or other natural disaster in that region. The loss of a key vendor or any interruption or delay in the availability or supply of PVC resin could disrupt our ability to deliver our plastic products, cause customers to cancel orders or require us to incur additional expenses to obtain PVC resin from alternative sources, if such sources are available.

We compete against a large number of other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors.

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

Reductions in PVC resin prices can negatively affect our plastics business.

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

MANUFACTURING

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

Our manufacturing businesses are subject to intense risks associated with competition from foreign and domestic manufacturers, many of whom have broader product lines, greater distribution capabilities, greater capital resources, larger marketing, research and development staffs and facilities and other capabilities that may place downward pressure on margins and profitability. The companies in our manufacturing segment use a variety of raw materials in the products they manufacture, including steel, lumber, concrete, aluminum and resin. Costs for these items have increased significantly and may continue to increase. If our manufacturing businesses are not able to pass on the cost of their increases to their customers, it could have a negative effect on profit margins in our manufacturing segment. Each of our manufacturing companies has significant customers and concentrated sales to such customers. If our relationships with significant customers should change materially, it would be difficult to immediately and profitably replace lost sales. Fluctuations in foreign currency exchange rates could have a negative impact on the net income and competitive position of our wind tower manufacturing operations in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars. We believe the demand for wind towers that we manufacture will depend primarily on the existence of either renewable portfolio standards or the Federal Production Tax Credit for wind energy. This credit is scheduled to expire on December 31, 2009. Our wind tower manufacturer, as well as our electrical contracting business in our other business segment, could be adversely affected if the tax credit in not extended or renewed.

HEALTH SERVICES

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

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

Our health services businesses may be unable to renew and continue to maintain the dealership and other agreements with Philips Medical from which it derives significant revenues from the sale and service of Philips Medical diagnostic imaging equipment.

This agreement is scheduled to expire on December 31, 2008 and also includes certain compliance requirements. If we are not able to renew such agreements or comply with the agreement, the financial results of our health services operations would be adversely affected.

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

Although we believe substantially all of our diagnostic imaging systems can be upgraded to maintain their state-of-the-art character, the development of new technologies or refinements of existing technologies might make our

Table of Contents

existing systems technologically or economically obsolete, or cause a reduction in the value of, or reduce the need for, our systems.

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

Our health services operations are subject to federal and state regulations relating to licensure, conduct of operations, ownership of facilities, addition of facilities and services and payment of services. Our failure to comply with these regulations, including new regulations released October 30, 2009 by the Center for Medicare & Medical Services, or our inability to obtain and maintain necessary regulatory approvals, may result in adverse actions by regulators with respect to our health services operations, which may include civil and criminal penalties, damages, fines, injunctions, operating restrictions or suspension of operations. Any such action could adversely affect our financial results. Courts and regulatory authorities have not fully interpreted a significant number of these laws and regulations, and this uncertainty in interpretation increases the risk that we may be found to be in violation. Any action brought against us for violation of these laws or regulations, even if successfully defended, may result in significant legal expenses and divert management s attention from the operation of our businesses.

FOOD INGREDIENT PROCESSING

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

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

The principal raw material used by our potato processing company is washed process-grade potatoes from growers. These potatoes are unsuitable for use in other markets due to imperfections. They are not subject to the United States Department of Agriculture s general requirements and expectations for size, shape or color. While our food ingredient processing company has processing capabilities in three geographically distinct growing regions, there can be no assurance it will be able to obtain raw materials due to poor growing conditions, a loss of key growers and other factors. A loss or shortage of raw materials or the necessity of paying much higher prices for raw materials or natural gas could adversely affect the financial performance of this company. Fluctuations in foreign currency exchange rates could have a negative impact on our potato processing company s net income and competitive position because approximately 26% of IPH sales in the first nine months of 2008 were outside the United States and the Canadian plant pays its operating expenses in Canadian dollars.

OTHER BUSINESS OPERATIONS

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

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

Table of Contents

Item 6. Exhibits

4.1 Credit Agreement, dated as of July 30, 2008, among Otter Tail Corporation, the Banks named therein, Bank of America, N.A., as Syndication Agent, U.S. Bank National Association, a national banking association, as agent for the Banks, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, and Merrill Lynch Bank USA (incorporated by reference to Exhibit 4.1 to Otter Tail Corporation s Form 8-K filed August 1, 2008)

4.2 Second Amendment to Note Purchase Agreement, dated as of September 11, 2008, among the Company and the noteholders party thereto (amending that certain Note Purchase Agreement, dated as of August 20, 2007, among the Company and each of the purchasers party thereto) (incorporated by reference to Exhibit 4.1 to Otter Tail Corporation s Form 8-K filed September 15, 2008)

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
(Chief Financial Officer/Authorized Officer)

Dated: November 7, 2008

Table of Contents

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