Otter Tail Corp
Form 10-Q
August 09, 2010

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2010

OR

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

For the transition period from to

Commission file number 0-53713

OTTER TAIL CORPORATION
(Exact name of registrant as specified in its charter)

Minnesota	27-0383995
(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 x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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 x 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 x

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

July 31, 2010 – 35,932,339 Common Shares ($5 par value)

OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands)	June 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	$--	$4,432
Accounts Receivable:		
Trade—Net	116,609	95,747
Other	11,308	10,883
Inventories	94,089	86,515
Deferred Income Taxes	11,402	11,457
Accrued Utility and Cost-of-Energy Revenues	10,406	15,840
Costs and Estimated Earnings in Excess of Billings	76,150	61,835
Income Taxes Receivable	10,968	48,049
Other	22,144	15,265
Total Current Assets	353,076	350,023
Investments	9,738	9,889
Other Assets	26,611	26,098
Goodwill	94,306	106,778
Other Intangibles—Net	27,757	33,887
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	10,874	10,676
Regulatory Assets	123,096	118,700
Total Deferred Debits	133,970	129,376
Plant		
Electric Plant in Service	1,314,648	1,313,015
Nonelectric Operations	381,092	362,088
Construction Work in Progress	37,204	23,363
Total Gross Plant	1,732,944	1,698,466
Less Accumulated Depreciation and Amortization	633,163	599,839
Net Plant	1,099,781	1,098,627
Total	$1,745,239	$1,754,678

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	June 30, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$67,587	$7,585
Current Maturities of Long-Term Debt	734	59,053
Accounts Payable	94,710	83,724
Accrued Salaries and Wages	18,821	21,057
Accrued Taxes	8,753	11,304
Derivative Liabilities	18,083	14,681
Other Accrued Liabilities	9,377	9,638
Total Current Liabilities	218,065	207,042
Pensions Benefit Liability	97,430	95,039
Other Postretirement Benefits Liability	38,602	37,712
Other Noncurrent Liabilities	23,726	22,697
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	163,019	155,306
Deferred Tax Credits	46,302	47,660
Regulatory Liabilities	65,299	64,274
Other	493	562
Total Deferred Credits	275,113	267,802
Capitalization		
Long-Term Debt, Net of Current Maturities	435,898	436,170
Class B Stock Options of Subsidiary	539	1,220
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2010 and 2009 – 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, 2010—35,932,339 Shares; 2009—35,812,280 Shares	179,662	179,061
Premium on Common Shares	249,931	250,398

Retained Earnings	212,036	243,352
Accumulated Other Comprehensive Loss	(1,263)	(1,315)
Total Common Equity	640,366	671,496
Total Capitalization	1,092,303	1,124,386
Total	$1,745,239	$1,754,678

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating Revenues				
Electric	$76,233	$70,610	$167,247	$159,089
Nonelectric	193,962	176,247	365,134	365,007
Total Operating Revenues	270,195	246,857	532,381	524,096
Operating Expenses				
Production Fuel - Electric	16,492	11,754	37,401	30,413
Purchased Power - Electric System Use	10,420	11,877	22,476	29,250
Electric Operation and Maintenance Expenses	29,084	28,959	57,406	55,889
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	150,126	135,319	282,038	288,280
Other Nonelectric Expenses	35,116	32,410	65,887	63,044
Asset Impairment Charge	19,740	--	19,740	--
Product Recall and Testing Costs	--	--	--	1,766
Depreciation and Amortization	19,883	18,103	39,634	35,920
Property Taxes - Electric	2,477	2,255	4,951	4,745
Total Operating Expenses	283,338	240,677	529,533	509,307
Operating Income (Loss)	(13,143)	6,180	2,848	14,789
Other Income	1,788	1,351	1,924	2,018
Interest Charges	9,405	6,652	18,435	12,922
Income (Loss) Before Income Taxes	(20,760)	879	(13,663)	3,885
Income Tax Benefit	(6,542)	(1,852)	(4,162)	(3,234)
Net Income (Loss)	(14,218)	2,731	(9,501)	7,119
Preferred Dividend Requirement and Other Adjustments	279	184	463	368
Earnings Available for Common Shares	$(14,497)	$2,547	$(9,964)	$6,751
Average Number of Common Shares Outstanding—Basic	35,799,231	35,388,754	35,759,901	35,356,745
Average Number of Common Shares Outstanding—Diluted	35,799,231	35,643,707	35,759,901	35,610,545
Earnings Per Common Share:				
Basic	$(0.40)	$0.07	$(0.28)	$0.19
Diluted	$(0.40)	$0.07	$(0.28)	$0.19
Dividends Per Common Share	$0.2975	$0.2975	$0.5950	$0.5950

See accompanying notes to consolidated financial statements.

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

(in thousands)	Six Months Ended June 30, 2010	2009
Cash Flows from Operating Activities		
Net Income (Loss)	$(9,501)	$7,119
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	39,634	35,920
Asset Impairment Charge	19,740	--
Deferred Tax Credits	(1,358)	(1,075)
Deferred Income Taxes	7,442	9,614
Change in Deferred Debits and Other Assets	(845)	(538)
Change in Noncurrent Liabilities and Deferred Credits	4,471	3,826
Allowance for Equity Funds Used During Construction	--	(1,003)
Change in Derivatives Net of Regulatory Deferral	(313)	(661)
Stock Compensation Expense – Equity Awards	1,320	1,754
Other—Net	(389)	139
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(21,307)	33,264
Change in Inventories	(7,771)	10,130
Change in Other Current Assets	(15,761)	18,688
Change in Payables and Other Current Liabilities	(1,798)	(41,161)
Change in Interest Payable and Income Taxes Receivable/Payable	35,855	14,289
Net Cash Provided by Operating Activities	49,419	90,305
Cash Flows from Investing Activities		
Capital Expenditures	(39,565)	(57,930)
Proceeds from Disposal of Noncurrent Assets	1,999	4,551
Net Increase in Other Investments	(808)	(66,671)
Net Cash Used in Investing Activities	(38,374)	(120,050)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	7,228	--
Net Short-Term Borrowings	60,002	(15,000)
Proceeds from Issuance of Common Stock	549	1,901
Proceeds from Issuance of Class B Stock of Subsidiary	153	--
Common Stock Issuance Expenses	(142)	(17)
Payments for Retirement of Common Stock	(401)	(229)
Payments for Retirement of Class B Stock of Subsidiary	(994)	--
Proceeds from Issuance of Long-Term Debt	95	75,004
Short-Term and Long-Term Debt Issuance Expenses	(1,598)	(3,175)
Payments for Retirement of Long-Term Debt	(58,693)	(5,438)
Dividends Paid and Other Distributions	(21,812)	(21,457)
Net Cash (Used in) Provided by Financing Activities	(15,613)	31,589
Effect of Foreign Exchange Rate Fluctuations on Cash	136	(353)
Net Change in Cash and Cash Equivalents	(4,432)	1,491

Cash and Cash Equivalents at Beginning of Period	4,432	7,565
Cash and Cash Equivalents at End of Period	$--	$9,056

See accompanying notes to consolidated financial statements.

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 financial statements 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, 2009, 2008 and 2007 included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2009. Because of seasonal and other factors, the earnings for the three-month and six-month periods ended June 30, 2010 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 of the notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

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 Otter Tail Power Company’s (OTP’s) forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 815-10-45-9. 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 25.6% for the three months ended June 30, 2010 compared with 25.7% for the three months ended June 30, 2009 and 24.8% for the six months ended June 30, 2010 compared with 27.6% for the six months ended June 30, 2009. 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 and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at any point in time during a contract, a projected loss for the entire contract is estimated and recognized.

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

(in thousands)	June 30, 2010	December 31, 2009
Costs Incurred on Uncompleted Contracts	$385,163	$400,577

Less Billings to Date	(354,729)	(400,711)
Plus Estimated Earnings Recognized	41,915	59,202
	$72,349	$59,068

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

(in thousands)	June 30, 2010	December 31, 2009
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$76,150	$61,835
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(3,801)	(2,767)
	$72,349	$59,068

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI), the Company's wind tower manufacturer, were $66,597,000 as of June 30, 2010 and $54,977,000 as of December 31, 2009. This amount is related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

Retainage

Accounts Receivable include amounts billed by the Company's subsidiaries under contracts that have been retained by customers pending project completion of $9,239,000 on June 30, 2010 and $9,215,000 on December 31, 2009.

Sales of Receivables

DMI is a party to a $40 million receivables purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement expires in March 2011. Accounts receivable sold totaled $29,300,000 in the first six months of 2010 compared with $64,800,000 in the first six months of 2009. Discounts, fees and commissions charged to operating expenses for the three month periods ended June 30, 2010 and 2009 were $75,000 and $92,000, respectively. Discounts, fees and commissions charged to operating expenses for the six month periods ended June 30, 2010 and 2009 were $107,000 and $267,000, respectively. In compliance with guidance under ASC 860-20, Sales of Financial Assets, 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 business, 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 guidance under ASC 605-50, Customer Payments and Incentives. 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 charged to revenue for the three month periods ended June 30, 2010 and 2009 were $24,000 and $88,000, respectively. Financing assistance costs charged to revenue for the six month periods ended June 30, 2010 and 2009 were $84,000 and $233,000, respectively.

Supplemental Disclosures of Cash Flow Information

	Six Months Ended June 30,	
(in thousands)	2010	2009
Increases in Accounts Payable Related to Capital Expenditures	$745	$330

Fair Value Measurements

The Company applies authoritative accounting guidance under ASC 820, Fair Value Measurements and Disclosures, which provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. ASC 820-10-35 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 hierarchy and examples of each level follow:

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 and may include complex and subjective models and forecasts.

The following table presents, for each of these hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2010 and December 31, 2009:

June 30, 2010 (in thousands)		Level 1		Level 2	Level 3
Assets:					
Investments for Nonqualified Retirement Savings Retirement Plan:					
Money Market and Mutual Funds and Cash	$	1,442	$	--	
Forward Energy Contracts				8,321	
Investments of Captive Insurance Company:					
Corporate Debt Securities		8,201			
Total Assets	$	9,643	$	8,321	
Liabilities:					
Forward Energy Contracts	$	--	$	17,986	
Foreign Currency Exchange Forward Windows				97	
Total Liabilities	$	--	$	18,083	

December 31, 2009 (in thousands)		Level 1		Level 2	Level 3
Assets:					
Investments for Nonqualified Retirement Savings Retirement Plan:					
Money Market and Mutual Funds and Cash	$	731	$	--	
Forward Energy Contracts				8,321	
Investments of Captive Insurance Company:					
Corporate Debt Securities		7,795			
U.S. Government Debt Securities		253			
Total Assets	$	8,779	$	8,321	
Liabilities:					
Forward Energy Contracts	$	--	$	14,681	
Total Liabilities	$	--	$	14,681	

Inventories

Inventories consist of the following:

(in thousands)		June 30, 2010		December 31, 2009
Finished Goods	$	46,425	$	42,784
Work in Process		7,460		3,824
Raw Material, Fuel and Supplies		40,204		39,907
Total Inventories	$	94,089	$	86,515

Goodwill and Other Intangible Assets
The Company accounts for goodwill and other intangible assets in accordance with the requirements of ASC 350, Intangibles—Goodwill and Other, requiring goodwill and indefinite-lived intangible assets to be measured for impairment at least annually, and more often when events indicate the assets may be impaired. Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC 360-10-35, Property, Plant, and Equipment—Overall—Subsequent Measurement.

During the first six months of 2010, ShoreMaster's performance was below its 2010 budget and below its performance over the same period in 2009. While updating the second quarter earnings forecast, it became apparent that ShoreMaster's commercial marina and waterfront lines of business continued to be adversely impacted by the economic recession in 2010. The Consumer Confidence Index declined 9.8% in June 2010 around increasing uncertainty and apprehension about the future state of the economy and labor market. The Purchasing Managers' Index also experienced a drop in June around concerns over the status of the economic recovery. These conditions have resulted in a reduction in incoming orders in the commercial marina business. As a result of the poor first half 2010 performance and new economic indicators, ShoreMaster's new forecast projects a slower recovery from the economic recession than was expected in 2009.

In light of the continuing economic uncertainty and delayed economic recovery, ShoreMaster revised its current sales and operating cash flow projections downward and reassessed its fair value to determine if its goodwill and other assets were impaired. ShoreMaster used a discounted cash flow model using a risk adjusted weighted average cost of capital discount rate of 14% to determine its fair value. The fair value determination indicated ShoreMaster's goodwill and intangible assets were 100% impaired and its long-lived assets were partially impaired, resulting in the following impairment charges in June 2010:

(in thousands)		
Goodwill	$	12,259
Brand/Trade Name		4,869
Other Intangible Assets		507
Long-Lived Assets		2,105
Total Asset Impairment Charges	$	19,740

As a result of the sale of certain imaging assets and routes in the Health Services segment in the second quarter of 2010, goodwill was reduced by $213,000.

The following table summarizes changes to goodwill by business segment during the first six months of 2010:

(in thousands)	Balance December 31, 2009	Adjustment to Goodwill in 2010	Goodwill Acquired in 2010	Balance June 30, 2010
Plastics	$ 19,302	$ --	$ --	$ 19,302
Manufacturing	24,732	(12,259)	--	12,473
Health Services	23,878	(213)	--	23,665
Food Ingredient Processing	24,324	--	--	24,324
Other Business Operations	14,542	--	--	14,542
Total	$ 106,778	$ (12,472)	$ --	$ 94,306

The following table summarizes the components of the Company's intangible assets at June 30, 2010 and December 31, 2009:

June 30, 2010 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Customer Relationships	$ 26,946	$ 4,318	$ 22,628	15 – 25 years
Covenants Not to Compete	1,704	1,627	77	3 – 5 years
Other Intangible Assets Including Contracts	930	890	40	5 – 30 years
Total	$ 29,580	$ 6,835	$ 22,745	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 5,012	$ --	$ 5,012	
December 31, 2009 (in thousands)				
Amortized Intangible Assets:				
Customer Relationships	$ 26,956	$ 3,696	$ 23,260	15 – 25 years
Covenants Not to Compete	2,190	2,047	143	3 – 5 years
Other Intangible Assets Including Contracts	2,358	1,757	601	5 – 30 years
Total	$ 31,504	$ 7,500	$ 24,004	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,883	$ --	$ 9,883	

The amortization expense for these intangible assets was $746,000 for the six months ended June 30, 2010 compared with $835,000 for the six months ended June 30, 2009. The estimated annual amortization expense for these intangible assets for the next five years is $1,349,000 for 2010, $1,274,000 for 2011, $1,255,000 for 2012, $1,251,000 for 2013 and $1,251,000 for 2014.

Comprehensive Income

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2010	2009	2010	2009
Net (Loss) Income	$(14,218)	$2,731	$(9,501)	$7,119
Other Comprehensive (Loss) Income (net-of-tax):				
Foreign Currency Translation (Loss) Gain	(676)	1,008	(188)	584
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	104	89	209	104
Unrealized Gain (Loss) on Available-for-Sale Securities	(8)	81	31	26
Total Other Comprehensive (Loss) Income	(580)	1,178	52	714
Total Comprehensive (Loss) Income	$(14,798)	$3,909	$(9,449)	$7,833

New Accounting Standards

Consolidation of Variable Interest Entities—In June 2009, the FASB issued new guidance on consolidation of variable interest entities. The guidance affects various elements of consolidation, including the determination of whether an entity is a variable interest entity and whether an enterprise is a variable interest entity's primary beneficiary. These updates to the Accounting Standards Codification are effective for interim and annual periods beginning after November 15, 2009. The Company implemented the guidance on January 1, 2010 and the implementation did not have a material impact on its consolidated financial statements.

Accounting Standards Update (ASU) No. 2010-06 Fair Value Measurements and Disclosures (Topic 820)—Improving Disclosures about Fair Value Measurements, issued by the FASB in January 2010, updates ASC 820 to require new disclosures for assets and liabilities measured at fair value. The requirements include expanded disclosure of valuation methodologies for fair value measurements, transfers between levels of the fair value hierarchy, and gross rather than net presentation of certain changes in Level 3 fair value measurements. The updates to ASC 820 contained in ASU No. 2010-06 were effective for interim and annual periods beginning after December 15, 2009, except for requirements related to gross presentation of certain changes in Level 3 fair value measurements, which are effective for interim and annual periods beginning after December 15, 2010. The implementation of applicable guidance from ASU No. 2010-06 on January 1, 2010 did not have a material impact on the Company's consolidated financial statements, but did require additional fair value disclosures in footnotes to interim financial statements, similar to disclosures required with year-end financial statements.

2. Segment Information

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

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by the Company's subsidiary, OTP. In addition, OTP is an active wholesale participant in the Midwest Independent Transmission System Operator (MISO) markets. OTP's operations have been the Company's primary business since 1907.

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

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, water, 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 four Canadian provinces.

The Company's electric operations, including wholesale power sales, are operated by its wholly owned subsidiary, OTP, and its energy services operation is operated by a separate wholly owned subsidiary of the Company. All of the Company's other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar).

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 one customer within the manufacturing segment that accounted for 13.6% of the Company's consolidated revenues in 2009. No other single external customer accounts for 10% or more of the Company's consolidated revenues. Substantially all of the Company's long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
United States of America	97.5 %	97.3 %	97.0 %	97.9 %
Canada	1.4 %	1.3 %	2.0 %	1.0 %
All Other Countries (none greater than 1%)	1.1 %	1.4 %	1.0 %	1.1 %

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for three and six month periods ended June 30, 2010 and 2009 and total assets by business segment as of June 30, 2010 and December 31, 2009 are presented in the following tables:

Operating Revenue

(in thousands)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Electric	$76,284	$70,663	$167,370	$159,204
Plastics	26,739	22,183	49,826	35,713
Manufacturing	84,411	76,843	162,989	172,862
Health Services	23,645	28,192	48,816	56,359
Food Ingredient Processing	18,255	20,581	37,170	40,667
Other Business Operations	42,173	29,597	68,475	61,492
Corporate Revenues and Intersegment Eliminations	(1,312)	(1,202)	(2,265)	(2,201)
Total	$270,195	$246,857	$532,381	$524,096

Interest Expense

(in thousands)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Electric	$5,328	$4,266	$10,582	$8,277
Plastics	428	199	791	399
Manufacturing	2,719	1,439	5,185	2,718
Health Services	280	100	525	196
Food Ingredient Processing	28	10	65	20
Other Business Operations	300	112	536	232
Corporate and Intersegment Eliminations	322	526	751	1,080
Total	$9,405	$6,652	$18,435	$12,922

Income Tax (Benefit) Expense

(in thousands)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Electric	$(452)	$(832)	$4,446	$939
Plastics	141	198	635	(1,449)

Manufacturing	(5,616)	(208)	(5,881)	(1,012)
Health Services	55	(63)	(377)	(76)
Food Ingredient Processing	1,110	1,613	1,837	2,338
Other Business Operations	(97)	(944)	(1,523)	(1,150)
Corporate	(1,683)	(1,616)	(3,299)	(2,824)
Total	$(6,542)	$(1,852)	$(4,162)	$(3,234)

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Earnings Available for Common Shares

(in thousands)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Electric	$4,531	$4,211	$12,152	$12,553
Plastics	232	291	1,013	(2,167)
Manufacturing	(18,178)	(167)	(18,335)	(1,257)
Health Services	35	(153)	(656)	(226)
Food Ingredient Processing	1,882	2,325	3,286	3,772
Other Business Operations	(170)	(1,456)	(2,334)	(1,781)
Corporate	(2,829)	(2,504)	(5,090)	(4,143)
Total	$(14,497)	$2,547	$(9,964)	$6,751

Total Assets

(in thousands)	June 30, 2010	December 31, 2009
Electric	$ 1,081,043	$ 1,119,822
Plastics	78,799	70,380
Manufacturing	309,477	306,011
Health Services	67,205	58,164
Food Ingredient Processing	91,474	88,478
Other Business Operations	70,339	59,915
Corporate	46,902	51,908
Total	$ 1,745,239	$ 1,754,678

3. Rate and Regulatory Matters

Minnesota

2007 General Rate Case Filing—In an order issued by the Minnesota Public Utilities Commission (MPUC) on August 1, 2008 OTP was granted an increase in Minnesota retail electric rates of $3.8 million, or approximately 2.9%, which went into effect in February 2009. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. An interim rate increase of 5.4% was in effect from November 30, 2007 through January 31, 2009. Amounts refundable totaling $3.9 million had been recorded as a liability on the Company’s consolidated balance sheet as of December 31, 2008. An additional $0.5 million refund liability was accrued in January 2009. OTP refunded Minnesota customers the difference between interim and final rates, with interest, in March 2009. In June 2008, OTP deferred recognition of $1.5 million in rate case-related regulatory assessments and fees of outside experts and attorneys that are subject to amortization and recovery over a three-year period beginning in February 2009.

2010 General Rate Case Filing—OTP filed a general rate case in Minnesota on April 2, 2010 requesting an interim rate increase of approximately 3.8%, or $5.0 million in annual revenue, effective June 1, 2010, and a final overall rate increase of approximately 8.0%, or $10.6 million in annual revenue. On May 27, 2010 the MPUC approved a 3.8% interim rate increase to be effective with customer usage on and after June 1, 2010. Several parties have intervened and discovery is ongoing. Evidentiary hearings are scheduled for November 17-19, 2010, and a decision is expected by May 2011. Interim rates will remain in effect for all Minnesota customers until the MPUC makes a final determination on the request. If final rates are lower than interim rates, OTP will refund Minnesota customers the difference, with interest.

Capacity Expansion 2020 (CapX2020) Fargo–Monticello 345 kiloVolt (kV) Project, Brookings–Southeast Twin Cities 345 kV Project and Twin Cities–LaCrosse 345 kV Project—On April 16, 2009 the MPUC approved the Certificates of Need (CONs) for the three 345 kV Group 1 CapX2020 line projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Twin Cities-LaCrosse). The MPUC CON orders were appealed to the Minnesota Court of Appeals on October 9, 2009 and in June 2009 the appellate court rejected the appeal.

The route permit application for the Monticello to St. Cloud portion of the Fargo project was filed in April 2009. The MPUC approved the route permit application and issued a written order on July 12, 2010. The Minnesota route permit application for the St. Cloud to Fargo portion of the Fargo project was filed on October 1, 2009. The MPUC is expected to make a determination on the route permit application in the first or second quarter of 2011. Regulatory filings will be made in North Dakota for the North Dakota portion of the Fargo–Monticello 345 kV project in the third and fourth quarters of 2010.

The route permit application for the Brookings project was filed in fourth quarter of 2008. On July 15, 2010 the MPUC voted to approve most of the Brookings route permit application, with the exception of the segment that crosses the Minnesota River. The MPUC has asked an administrative law judge to review additional evidence provided by the U.S. Fish and Wildlife Agency related to this section of the proposed route. OTP expects a final decision by the MPUC in the first or second quarter of 2011 on the final line segment. An application for a South Dakota route permit is under development and is expected to be filed with the South Dakota Public Utilities Commission (SDPUC) in the fourth quarter of 2010.

CapX2020 Bemidji–Grand Rapids 230 kV Project—OTP serves as the lead utility for the CapX2020 Bemidji-Grand Rapids 230-kV project, which has an expected in-service date of 2012-2013. OTP filed an application for a CON for this project on March 17, 2008. The CON was issued on July 9, 2009 and the written order from the MPUC was received on July 14, 2009. No appeal was made on this decision and the appeal timeline has expired.

A route permit application was filed with the MPUC in the second quarter of 2008 for the Bemidji-Grand Rapids project. Public hearings and evidentiary hearings were held in the first quarter of 2010 and the project is awaiting a recommendation from an administrative law judge. A decision from the MPUC on the route permit application is expected in the third or fourth quarter of 2010. In addition to the route permit, a federal Environmental Impact Statement (EIS) is required for this project. The Rural Utilities Service is the lead agency in the development of the federal EIS. A record of decision on the project is expected by the end of the fourth quarter of 2010.

Renewable Energy Standards, Conservation, Renewable Resource Riders and Transmission Riders—The state of Minnesota has a renewable energy standard which requires OTP 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. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. OTP has sufficient renewable energy resources available and in service to comply with the required 2016 level of the Minnesota renewable energy standard. OTP’s compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

Under the Next Generation Energy Act of 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover investments and costs incurred to satisfy the requirements of the renewable energy standards. The MPUC is authorized to approve a rate schedule rider to enable utilities to recover the costs of qualifying renewable energy projects that 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. 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 OTP’s proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in qualifying renewable energy facilities. The rider enables OTP to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Minnesota Renewable Resource Adjustment (MNRRA) of $0.0019 per kilowatt-hour (kwh) was included on Minnesota customers' electric service statements beginning in September 2008, reflecting cost recovery for OTP's twenty-seven 1.5 megawatt (MW) wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008.

The MPUC approved OTP's petition for a 2009 MNRRA in July 2009, which increased the MNRRA rate to provide cost recovery for its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008. This approval increased the 2009 MNRRA to $0.00415 per kwh for the recovery of $6.6 million through March 31, 2010—$4.0 million from August through December 2009 and $2.6 million from January through March 2010. The approval also granted OTP authority to recover over a 48-month period beginning in April 2010 accrued renewable resource recovery revenues that had not previously been recovered. OTP has recognized a regulatory asset of $7.0 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of June 30, 2010. On January 12, 2010, the MPUC issued an order finding OTP's Luverne Wind Farm project eligible for cost recovery through the MNRRA. The 2010 annual MNRRA cost recovery filing was made on December 31, 2009 with a requested effective date of April 1, 2010. The MNOES has taken the position that OTP's internal costs should be excluded from recovery under the MNRRA. OTP filed reply comments in opposition to the MNOES's position. As of the date of this report on Form 10-Q, the MPUC has not rendered a decision on OTP's petition for a 2010 MNRRA.

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 transmission facilities that have been previously approved by the MPUC in a CON proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or otherwise deemed eligible by the MPUC. Such transmission cost recovery riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. OTP's request for approval of a transmission cost recovery rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010. Beginning February 1, 2010, OTP's transmission rider rate is reflected on Minnesota customer electric service statements at $0.00039 per kwh plus $0.035 per kW for large general service customers and $0.00007 per kwh for controlled service customers, $0.00025 per kwh for lighting customers, and $0.00057 per kwh for all other customers. As of June 30, 2010 OTP had accrued $0.2 million in revenues that are eligible for recovery through the rider but have not been billed. In a request for a revenue increase under general rates filed with the MPUC on April 2, 2010, OTP has requested recovery of its transmission investments currently being recovered through OTP's Minnesota transmission rider rate. The transmission investments will continue to be recovered through OTP's Minnesota transmission rider rate until the MPUC makes a decision on OTP's general rate case.

North Dakota

General Rate Case—On November 3, 2008 OTP 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 of approximately 4.1%, or $4.8 million annualized, that went into effect on January 2, 2009. In an order issued by the North Dakota Public Service Commission (NDPSC) on November 25, 2009, OTP was granted an increase in North Dakota retail electric rates of $3.6 million, or approximately 3.0%, which went into effect in December 2009. The NDPSC order authorizing an interim rate increase requires OTP to refund North Dakota customers the difference between final and interim rates, with interest. OTP established a refund reserve for revenues collected under interim rates that exceeded the final rate increase. The refund reserve balance was $0.9 million as of December 31, 2009, which was refunded to North Dakota customers in January 2010. OTP deferred recognition of $0.5 million in rate case-related filing and administrative costs that are subject to amortization and recovery over a three year period beginning in January 2010.

Renewable Resource Cost Recovery Rider—On May 21, 2008 the NDPSC approved OTP's request for a Renewable Resource Cost Recovery Rider to enable OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The North Dakota Renewable Resource Cost Recovery Rider Adjustment (NDRRA) of $0.00193 per kwh was included on North Dakota customers' electric service statements beginning in June 2008, and reflects cost recovery for OTP's twenty-seven 1.5 MW wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008. The rider also allows OTP to recover costs associated with other new renewable energy projects as they are completed. OTP included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008 in its 2009 annual request to the NDPSC to increase the amount of the NDRRA. An NDRRA of

$0.0051 per kwh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009.

In a proceeding that was combined with OTP's general rate case, the NDPSC reviewed whether to move the costs of the projects currently being recovered through the NDRRA into base rate cost recovery and whether to make changes to the rider. A settlement of the general rate case and the NDRRA reduced the NDRRA to $0.00369 for the period from December 1, 2009 until the effective date for the next annual NDRRA filing, requested to be April 1, 2010. Because the 2008 annual NDRRA filing was combined with the general rate case proceedings (concluded in November 2009), the 2009 annual filing to establish the 2010 NDRRA (which includes cost recovery for OTP's investment in its Luverne Wind Farm project) was delayed until December 31, 2009, with a requested effective date of April 1, 2010. A consensus on a proposed settlement was reached by all parties at an informal hearing held by the NDPSC on June 30, 2010. The NDPSC will consider approval of OTP's petition based on the proposed settlement. As of the date of this report on Form 10-Q, the NDPSC had not rendered a decision on OTP's petition for a 2010 NDRRA.

OTP had not been deferring recognition of its renewable resource costs eligible for recovery under the NDRRA but had been charging those costs to operating expense since January 2008. After approval of the rider in May 2008, OTP accrued revenues related to its investment in renewable energy and for renewable energy costs incurred since January 2008 that were eligible for recovery through the NDRRA. Terms of the approved settlement provide for the recovery of accrued but unbilled NDRRA revenues over a period of 48 months beginning in January 2010. The Company's June 30, 2010 consolidated balance sheet includes a regulatory asset of $1.8 million for revenues that are eligible for recovery through the NDRRA but have not been billed to North Dakota customers.

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. OTP requested recovery of such costs in its general rate case filed in November 2008 and was granted recovery of such costs by the NDPSC in its November 25, 2009 order.

CapX2020 Request for Advance Determination of Prudence—On October 5, 2009 OTP filed an application for an advance determination of prudence with the NDPSC for its proposed participation in three of the four Group 1 projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Bemidji-Grand Rapids). An administrative law judge conducted an evidentiary hearing on the application in May of 2010. OTP entered into a settlement agreement with NDPSC Advocacy Staff and is awaiting a final decision by the NDPSC.

South Dakota

2008 General Rate Case Filing—On October 31, 2008 OTP filed a general rate case in South Dakota requesting an overall revenue increase of approximately $3.8 million, or 15.3%, which included, among other things, recovery of investments and expenses related to renewable resources in base rates. OTP increased rates by approximately 11.7% on a temporary basis beginning with electricity consumed on and after May 1, 2009, as allowed under South Dakota law. In an order issued by the SDPUC on June 30, 2009, OTP was granted an increase in South Dakota retail electric rates of $3.0 million or approximately 11.7%. OTP implemented final, approved rates in July 2009.

Federal

Revenue Sufficiency Guarantee (RSG) Charges—Since 2006, OTP has been a party to litigation before the FERC regarding the application of RSG charges to market participants who withdraw energy from the market or engage in financial-only, virtual sales of energy into the market or both. These litigated proceedings occurred in several electric rate and complaint dockets before the FERC and several of the FERC's orders are on review before the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit).

On November 7, 2008 the FERC issued an order on rehearing and compliance in the RSG proceeding, reversing its determination in a prior order and stating that MISO should remove the volume of virtual supply offers of market participants—not physically withdrawing energy—from the denominator of the rate calculation from April 25, 2006 forward. MISO interpreted the order to mean that all virtual supply offers and deviations in the denominator of the rate calculation that do not ultimately pay the rate should be removed from April 1, 2005 (start of the Energy Market) forward. On November 10, 2008 the FERC issued an order finding the current RSG rate unjust and unreasonable and accepting an interim rate that applied RSG charges to all virtual sales until such time as MISO makes a subsequent filing of the new RSG rate.

On May 6, 2009 the FERC issued an order on rehearing of the November 10, 2008 order. The May order relieved MISO from having to resettle RSG payments resulting from the FERC's earlier decision to remove the words "actually withdraws energy" (AWE) from the RSG tariff provisions. Absent this relief (or waiver), the removal of the AWE language would have had two relevant impacts on the RSG charge: (1) it would tend to reduce the RSG rate because the rate denominator would include all virtual supply volumes and (2) it would impose RSG charges on all cleared virtual supply transactions. The waiver applies to the period August 10, 2007 through November 9, 2008. Beginning November 10, 2008 the MISO is obliged to resettle RSG charges by recalculating the RSG rate and impose RSG charges on all virtual supply transactions.

On June 12, 2009 the FERC issued an order on rehearing of the November 7, 2008 order. The June order, at a minimum, relieved MISO from having to resettle RSG payments resulting from any difference between the megawatt hours associated with virtual supply in the denominator of the RSG rate and the billing determinants associated with virtual supply transactions (VSO mismatch). This relief (or waiver) applies to the period April 25, 2006 through November 4, 2007. Since OTP would have had a payment obligation during this period associated with the virtual supply and other mismatches, the June order eliminates that payment obligation. However, the June order, like many of the other orders in this docket, is subject to appellate review and potential reversal. Beginning from November 5, 2007, MISO is obligated to resettle to correct the VSO mismatch. As of September 30, 2009, OTP had paid all its resettlement obligations determined and imposed by MISO. On August 7, 2009 the FERC issued an order requiring MISO’s RSG Task Force to develop a recommendation on any transactions that should be exempted from paying RSG charges. The RSG Task Force has completed its review and provided recommendations to the FERC.

In an order issued on June 2, 2010 the FERC directed MISO to remove all changes it made in its December 2008 compliance filing other than removing AWE language. The FERC did not order refunds. On June 3, 2010 the FERC denied a request for rehearing submitted by three energy trading companies. The Company is unable to predict when these litigation proceedings will conclude.

Big Stone II Project

On June 30, 2005 OTP 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. On September 11, 2009 OTP announced its withdrawal—both as a participating utility and as the project’s lead developer—from Big Stone II, due to a number of factors. The broad economic downturn, a high level of uncertainty associated with proposed federal climate legislation and existing federal environmental regulations and challenging credit and equity markets made proceeding with Big Stone II and committing to approximately $400 million in capital expenditures untenable for OTP’s customers and the Company’s shareholders. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project.

In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers, pursuant to a final settlement agreement filed June 23, 2010, between the NDPSC Advocacy Staff, OTP and the North Dakota Large Industrial Energy Group, Interveners. The order modified the settlement agreement slightly by using OTP’s average 2009 Allowance for Funds Used During Construction (AFUDC) rate of 7.65%, rather than OTP’s approved rate of return of 8.62% from the NDPSC rate case order of November 25, 2009 as called for by the settlement agreement, to accrue carrying charges during the period from September 1, 2009 to entry of the NDPSC order. The terms of the settlement agreement indicate that OTP’s discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The total amount of Big Stone II generation costs incurred by OTP (which excludes $2,612,000 of project transmission-related costs) was determined to be $10,080,000, of which $4,064,000 represents North Dakota’s jurisdictional share.

OTP will include in its total recovery amount a carrying charge of approximately $285,000 on the North Dakota share of Big Stone II generation costs for the period from September 1, 2009 through the date the recovery of costs begins based on OTP’s average 2009 AFUDC rate of 7.65%. Because OTP will not earn a return on these deferred costs over the 36-month recovery period, the recoverable amount of $4,349,000 has been discounted to its present value of $3,913,000 using OTP’s incremental borrowing rate, in accordance with ASC 980, Regulated Operations, accounting requirements. The recovery of the North Dakota portion of Big Stone II generation costs will occur over 36 months beginning August 1, 2010.

The portion of Big Stone II costs incurred by OTP related to transmission is $2,612,000, of which $1,053,000 represents North Dakota's jurisdictional share. OTP transferred the North Dakota Share of Big Stone II transmission costs to Construction Work in Progress (CWIP), with such costs subject to AFUDC continuing from September 2009. If construction of all or a portion of the transmission facilities commences within three years of the NDPSC order approving the settlement agreement, the North Dakota portion of Big Stone II transmission costs and accumulated AFUDC shall be included in the rate base investment for these future transmission facilities. If construction is not commenced on any of the transmission facilities within three years of the NDPSC order approving the settlement agreement, OTP may petition the NDPSC to either continue accounting for these costs as CWIP or to commence recovery of such costs.

As of June 30, 2010 OTP had $7.7 million in incurred costs related to the project that have not been approved for recovery and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve its rates. In filings made on December 14, 2009, OTP requested from the MPUC and the SDPUC authority to reflect these costs on its books as a regulatory asset through the use of deferred accounting, pending a determination on the recoverability of the costs. OTP has requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010, and thereafter requested withdrawal of its December 14, 2009 request for deferred accounting as duplicative of the issues presented in the rate case. The SDPUC approved OTP's request for deferred accounting treatment on February 9, 2010. OTP will request recovery of the South Dakota portion of its Big Stone II development costs over a five-year period in its next general rate case filing in South Dakota, expected to be filed in the third quarter of 2010.

If Minnesota or South Dakota jurisdictions eventually deny recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed unrecoverable.

4. Regulatory Assets and Liabilities

As a regulated entity OTP accounts for the financial effects of regulation in accordance with ASC 980, Regulated Operations. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation.

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

(in thousands)	June 30, 2010	December 31, 2009
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$77,113	$78,871
Unrecovered Project Costs – Big Stone II	11,628	12,982
Deferred Marked-to-Market Losses	11,315	7,614
Minnesota Renewable Resource Rider Accrued Revenues	7,019	5,324
Deferred Income Taxes	5,749	5,441
Debt Reacquisition Premiums	3,727	3,051
Deferred Conservation Improvement Program Costs	3,051	1,908
Accumulated ARO Accretion/Depreciation Adjustment	2,009	1,808
North Dakota Renewable Resource Rider Accrued Revenues	1,819	566
General Rate Case Recoverable Expenses	1,563	1,693
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	904	1,091
South Dakota – Asset-Based Margin Sharing Shortfall	443	330
Deferred Holding Company Formation Costs	221	248
Minnesota Transmission Rider Accrued Revenues	171	420
MISO Schedule 16 and 17 Deferred Administrative Costs - MN	114	252
Plant Acquisition Costs	--	18
Accrued Cost-of-Energy (Refund) Revenue	(363)	1,175
Total Regulatory Assets	$126,483	$122,792
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$60,261	$58,937

Deferred Income Taxes	4,627	4,965
Deferred Marked-to-Market Gains	211	224
Other Regulatory Liabilities	200	148
Total Regulatory Liabilities	$65,299	$64,274
Net Regulatory Asset Position	$61,184	$58,518

The regulatory asset related to the unrecognized transition obligation, prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses 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 and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC 715, Compensation—Retirement Benefits, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

All Deferred Marked-to-Market Gains and Losses recorded as of June 30, 2010 are related to forward purchases of energy scheduled for delivery through December 2013.

Unrecovered Project Costs – Big Stone II are costs incurred by OTP related to its participation in the planned construction of a 500- to 600-megawatt generating unit at its Big Stone Plant site. On September 11, 2009 OTP announced its withdrawal from participation in the Big Stone II project due to a number of factors. OTP believes the costs it incurred during its participation in the project are probable of recovery in future rates and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve OTP's rates. In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers. The recovery of the $3,913,000 North Dakota portion of Big Stone II generation costs will occur over 36 months beginning August 1, 2010.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of June 30, 2010. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over the next 45 months.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with ASC 740, Income Taxes.

Debt Reacquisition Premiums included in Unamortized Debt Expense are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 23 years.

Deferred Conservation Program Costs represent mandated conservation expenditures and incentives recoverable through retail electric rates within the next 24 months.

The Accumulated ARO Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.

General Rate Case Recoverable Expenses will be recovered over the next 46 months.

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

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of June 30, 2010. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over the next 42 months.

South Dakota – Asset-Based Margin Sharing Shortfall represents a difference in OTP's South Dakota share of actual profit margins on wholesale sales of electricity from company-owned generating units and estimated profit margins from those sales that were used in determining current South Dakota retail electric rates. Net shortfalls or excess margins accumulated annually will be subject to recovery or refund through future retail rate adjustments in South

Dakota in the following year.

Minnesota Transmission Rider Accrued Revenues are expected to be recovered over the next 6 months.

Deferred Holding Company Formation Costs will be amortized over the next 48 months.

MISO Schedule 16 and 17 Deferred Administrative Costs – MN will be recovered over the next 5 months.

The Accrued Cost-of-Energy (Refund) is netted against Accrued Utility and Cost-of-Energy Revenues and will be credited to retail electric customers over the next 12 months.

The Accumulated Reserve for Estimated Removal Costs – Net of Salvage is reduced as actual removal costs are incurred.

Other Regulatory Liabilities includes: 1) a portion of profit margins on wholesales sales of purchased power subject to refund to South Dakota customers through future retail rate adjustments, and 2) a deferred gain on the sale of utility property that will be paid to Minnesota retail electric customers over the next 24 years.

If for any reason, OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its 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 guidance under ASC 980 ceases.

5. Forward Contracts Classified as Derivatives

Electricity Contracts
All of OTP's wholesale purchases and sales of energy under forward contracts that do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. OTP's objective in entering into forward contracts for the purchase and sale of energy is to optimize the use of its generating and transmission facilities and leverage its knowledge of wholesale energy markets in the region to maximize financial returns for the benefit of both its customers and shareholders. OTP's intent in entering into certain of these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. OTP also enters into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales.

As of June 30, 2010 OTP had recognized, on a pretax basis, $1,439,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and NYMEX. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in ASC 820-10-35.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of June 30, 2010 and December 31, 2009, and the change in the Company's consolidated balance sheet position from December 31, 2009 to June 30, 2010:

(in thousands)	June 30, 2010	December 31, 2009
Current Asset – Marked-to-Market Gain	$ 8,321	$ 8,321
Regulatory Asset – Deferred Marked-to-Market Loss	11,315	7,614
Total Assets	19,636	15,935
Current Liability – Marked-to-Market Loss	(17,986)	(14,681)
Regulatory Liability – Deferred Marked-to-Market Gain	(211)	(224)
Total Liabilities	(18,197)	(14,905)
Net Fair Value of Marked-to-Market Energy Contracts	$ 1,439	$ 1,030

(in thousands)	Year-to-Date June 30, 2010
Fair Value at Beginning of Year	$ 1,030
Less: Amount Realized on Contracts Entered into in 2009 and Settled in 2010	206
Changes in Fair Value of Contracts Entered into in 2009	--
Net Fair Value of Contracts Entered into in 2009 at End of Period	824
Changes in Fair Value of Contracts Entered into in 2010	615
Net Fair Value End of Period	$ 1,439

The $1,439,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on June 30, 2010 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	3rd Quarter 2010	4th Quarter 2010	2011	2012	Total
Net Gain	$ 717	$ 81	$ 320	$ 321	$1,439

Realized and unrealized net (losses) gains on forward energy contracts of $(24,000) for the three months ended June 30, 2010, $1,801,000 for the six months ended June 30, 2010, $140,000 for the three months ended June 30, 2009 and $1,174,000 for the six months ended June 30, 2009, are included in electric operating revenues on the Company's consolidated statements of income.

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength.

OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of June 30, 2010 was $796,000. As of June 30, 2010 OTP had a net credit risk exposure of $2,000,000 from five counterparties with investment grade credit ratings. OTP had no exposure at June 30, 2010 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The $2,000,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after June 30, 2010. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $1,108,000 on certain of OTP's derivative energy contracts included in the $17,986,000 derivative liability on June 30, 2010 are covered by deposited funds. Certain other of OTP's derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request immediate and ongoing full overnight collateralization on contracts in net liability positions. The aggregate fair value of all forward energy derivative contracts with credit-risk-related contingent features that were in a liability position on June 30, 2010 was $9,397,000, for which OTP had posted $6,086,000 as collateral in the form of offsetting gain positions on other contracts with its counterparties under master netting agreements. If the credit-risk-related contingent features underlying these agreements were triggered on June 30, 2010, OTP would have been required to post $3,311,000 in additional collateral to its counterparties. The remaining derivative liability balance of $7,481,000 relates to mark-to-market losses on contracts that have no ratings triggers or deposit requirements.

OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2009 was $222,000. As of December 31, 2009 OTP had a net credit risk exposure of $387,000 from four counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2009 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The $387,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $72,000 on certain of OTP's derivative energy contracts included in the $14,681,000 derivative liability on December 31, 2009 are covered by deposited funds. Certain other of OTP's derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request immediate and ongoing full overnight collateralization on contracts in net liability positions. The aggregate fair value of all forward energy derivative contracts with credit-risk-related contingent features that were in a liability position on December 31, 2009 was $7,958,000, for which OTP had posted $7,760,000 as collateral in the form of offsetting gain positions on other contracts with one of its counterparties under a master netting agreement. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, OTP would have been required to post $198,000 in additional collateral to its counterparties. The remaining derivative liability balance of $6,651,000 relates to mark-to-market losses on contracts that have no ratings triggers or deposit requirements.

Fuel Contracts
In order to limit its exposure to fluctuations in future prices of natural gas, IPH entered into contracts with a fuel supplier in December 2009 for firm purchases of natural gas to cover portions of its anticipated natural gas needs in Ririe, Idaho through August 2010 at fixed prices. These contracts qualify for the normal purchase exception to mark-to-market accounting under ASC 815-10-15.

Foreign Currency Exchange Forward Windows
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 May 2010 to cover approximately 70% of its Canadian dollar cash needs from May 2010 through December 2010. Each contract was for the exchange of $250,000 U.S. dollars for the amount of Canadian dollars stated in each contract. The following table lists the contracts outstanding as of June 30, 2010:

(in thousands)	Settlement Periods	USD	CAD
Contracts entered into in May 2010	July 2010 - December 2010	$3,750	$3,901

The following tables show the effect of marking to market IPH's foreign currency exchange forward windows and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of June 30, 2010 and December 31, 2009, and the change in the Company's consolidated balance sheet position from December 31, 2009 to June 30, 2010:

(in thousands)	June 30, 2010
Fair Value of IPH Foreign Currency Exchange Forward Windows included in:	
Other Current Assets	$--
Other Accrued Current Liabilities	(97)
Net Fair Value of Foreign Currency Exchange Forward Windows	$(97)

(in thousands)	Year-to-Date June 30, 2010
Fair Value at Beginning of Year	$ --
Changes in Fair Value of Contracts Entered into in 2010	(97)
Net Fair Value End of Period	$ (97)

These contracts are derivatives subject to mark-to-market accounting. IPH did 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. IPH intends to settle these contracts during their stated settlement periods and use the proceeds to pay its Canadian liabilities when they came due. These contracts do not qualify for hedge accounting treatment because the timing of their settlements will not coincide with the payment of specific bills or contractual obligations. The foreign currency exchange forward windows outstanding as of June 30, 2010 were valued and marked to market on June 30, 2010 based on quoted exchange values on June 30, 2010. Realized and unrealized net (losses) gains on IPH's foreign currency exchange forward windows of $(105,000) for the three and six month periods ended June 30, 2010, $234,000 for the three months ended June 30, 2009 and $90,000 for the six months ended June 30, 2009 are included in other income on the Company's consolidated statements of income.

6. Common Shares and Earnings Per Share

Common Shares
Following is a reconciliation of the Company's common shares outstanding from December 31, 2009 through June 30, 2010:

Common Shares Outstanding, December 31, 2009	35,812,280
Issuances:	
Executive Officer Stock Performance Awards	34,768
Restricted Stock Issued to Employees	31,600
Stock Options Exercised	27,800
Restricted Stock Issued to Nonemployee Directors	24,800
Vesting of Restricted Stock Units	18,965
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(17,874)
Common Shares Outstanding, June 30, 2010	35,932,339

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

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the three-month and six-month periods ended June 30, 2010 and 2009:

Three Months Ended June 30,	Options Outstanding	Range of Exercise Prices
2010	388,960	$24.93 – $31.34
2009	419,460	$24.93 – $31.34

Six Months Ended June 30,	Options Outstanding	Range of Exercise Prices
2010	388,960	$24.93 – $31.34
2009	419,460	$24.93 – $31.34

Common Stock Distribution Agreement
On March 17, 2010, the Company entered into a Distribution Agreement (the Agreement) with J.P. Morgan Securities Inc. (JPMS). Pursuant to the terms of the Agreement, the Company may offer and sell its common shares from time to time through JPMS, as the Company's distribution agent for the offer and sale of the shares, up to an aggregate sales price of $75,000,000.

Under the Agreement, the Company will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. Sales of the shares, if any, will be made by means of ordinary brokers' transactions on the NASDAQ Global Select Market at market prices or as otherwise agreed with JPMS. The Company may also agree to sell shares to JPMS, as principal for its own account, on terms agreed by the Company and JPMS in a separate agreement at the time of sale. JPMS will receive from the Company a commission of 2% of the gross sales price per share for any shares sold through it as the Company's distribution agent under the Agreement.

The Company is not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement. The shares, if issued, will be issued pursuant to the Company's existing shelf registration statement, as amended. No shares were sold pursuant to the agreement during the three months ended June 30, 2010.

7. Share-Based Payments

The Company has five share-based payment programs.

On April 12, 2010 the Company's Board of Directors granted 26,180 restricted stock units to key employees under the 1999 Stock Incentive Plan, as amended (Incentive Plan), payable in common shares on April 8, 2014, the date the units vest. The grant date fair value of each restricted stock unit was $17.76 per share based on the market value of the Company's common stock on April 12, 2010, discounted for the value of the dividend exclusion over the four-year vesting period.

On April 12, 2010 the Company's Board of Directors granted 24,800 shares of restricted stock to the Company's nonemployee directors and 31,600 shares of restricted stock to the Company's executive officers, including OTP's president, under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2011 through 2014 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $21.835 per share, the average market price on the date of grant.

On April 12, 2010 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 146,800 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, 2010 through December 31, 2012. The aggregate target share award is 73,400 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 target amount of common shares projected to be awarded was $20.97 per share, as determined under a Monte Carlo simulation valuation method. The terms of these awards are such that the entire award will be classified and accounted for as a liability, as required under ASC 718-10-25-18, and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

As of June 30, 2010 the remaining unrecognized compensation expense related to stock-based compensation was approximately $7.0 million (before income taxes) which will be amortized over a weighted-average period of 2.3 years.

Amounts of compensation expense recognized under the Company's five stock-based payment programs for the three-month and six-month periods ended June 30, 2010 and 2009 are presented in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2010	2009	2010	2009
Employee Stock Purchase Plan (15% discount)	$ 72	$ 72	$ 141	$ 162
Restricted Stock Granted to Directors	158	143	298	254
Restricted Stock Granted to Employees	162	111	280	202
Restricted Stock Units Granted to Employees	97	148	157	269
Stock Performance Awards Granted to Executive Officers	(65)	787	157	1,222
Totals	$ 424	$ 1,261	$ 1,033	$ 2,109

9. Commitments and Contingencies

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 alleged certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act (CAA) and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged 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 CAA and the South Dakota SIP. The Sierra Club alleged 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 sought both declaratory and injunctive relief to bring the defendants into compliance with the CAA 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 was and is being operated in compliance with the CAA and the South Dakota SIP.

The defendants filed a motion to dismiss the Sierra Club complaint on August 12, 2008. On March 31, 2009 and April 6, 2009, the U.S. District Court for the District of South Dakota (Northern Division) issued a Memorandum and Order and Amended Memorandum and Order, respectively, granting the defendants' motion to dismiss the Sierra Club complaint. On April 17, 2009 the Sierra Club filed a motion for reconsideration of the Amended Memorandum Opinion and Order. The Sierra Club motion was opposed by the defendants. The Sierra Club motion for reconsideration was denied on July 22, 2009. On July 30, 2009 the Sierra Club filed a notice of appeal to the 8th U.S. Circuit Court of Appeals. Briefing was complete on January 22, 2010 on filing of the Sierra Club's reply brief. Oral arguments before the Court of Appeals were heard on May 11, 2010. The ultimate outcome of this matter cannot be determined at this time.

Federal Power Act Complaint
On August 29, 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 the FERC alleging that OTP and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act (FPA) to deny RES and PEAK Wind access to the Pillsbury Line, an interconnection facility which Minnkota owns to interconnect generation projects being developed by OTP and NextEra Energy Resources, Inc. (fka FPL Energy, Inc.) (NextEra). RES and PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) the FERC direct MISO to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that OTP, Minnkota and NextEra 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 the FERC assess civil penalties against OTP. OTP answered the complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that the FERC dismiss the complaint. On October 14, 2008, RES and PEAK Wind filed an answer to OTP's answer and, restated the allegations included in the initial complaint. RES and PEAK Wind also added a request that the FERC rescind both OTP's waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, OTP filed a reply, denying the allegations made by RES and PEAK Wind in its answer. By order issued on December 19, 2008, the FERC set the complaint for hearing and established settlement procedures. A formal settlement agreement was filed with the FERC requesting approval of the settlement and withdrawal of the complaint. On May 6, 2010 the FERC issued an order approving the settlement and terminating the proceeding. The settlement did not have a material impact on OTP's financial position, results of operations or cash flows.

Other
The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of June 30, 2010 will not be material.

10. Short-Term and Long-Term Borrowings

The following table presents the status of our lines of credit as of June 30, 2010 and December 31, 2009:

(in thousands)	Line Limit	In Use on June 30, 2010	Restricted due to Outstanding	Available on June 30, 2010	Available on December 31,

					Letters of Credit				2009	
Otter Tail Corporation Credit Agreement	$	200,000	$	46,472	$	14,024	$	139,504	$	179,755
OTP Credit Agreement		170,000		20,994		250		148,756		167,735
Total	$	370,000	$	67,466	$	14,274	$	288,260	$	347,490

On May 4, 2010 the Company entered into a $200 million Second Amended and Restated Credit Agreement (the Credit Agreement) with the banks named therein, including U.S. Bank National Association, a national banking association, as administrative agent for the Banks and as Lead Arranger, Bank of America, N.A. and JPMorgan Chase Bank, National

Association, as Co-Syndication Agents, and KeyBank National Association, as Documentation Agent. The Credit Agreement amends and restates the Company's $200 million credit agreement dated as of December 23, 2008, and is an unsecured revolving credit facility that the Company can draw on to support its nonelectric operations. Borrowings under the Credit Agreement bear interest at LIBOR plus 3.25%, subject to adjustment based on the Company's senior unsecured credit ratings. The Credit Agreement expires on May 4, 2013. The Credit Agreement contains a number of restrictions on the Company and 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 Credit Agreement also contains affirmative covenants and events of default. The Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's credit ratings. The Company's obligations under the Credit Agreement are guaranteed by Varistar and its material subsidiaries. Outstanding letters of credit issued by the Company under the Credit Agreement can reduce the amount available for borrowing under the line by up to $50 million. The Credit Agreement has an accordion feature whereby the line can be increased to $250 million as described in the Credit Agreement.

On June 23, 2010 the Company entered into Amendment No. 3 to its Note Purchase Agreement dated as of February 23, 2007 with Cascade Investment, L.L.C., as amended (the Cascade Note Purchase Agreement). Amendment No. 3 amends certain covenants and related definitions contained in the Cascade Note Purchase Agreement to, among other things, provide the Company and its material subsidiaries with additional flexibility to incur certain customary liens, make certain investments, and give certain guaranties, in each case under the circumstances set forth in Amendment No. 3. On July 29, 2010 the Company entered into Amendment No. 4 to the Cascade Note Purchase Agreement, which was effective June 30, 2010. The amendments contained in Amendment No. 4 permit the Company to exclude impairment charges and write-offs of assets (including ShoreMaster's June 2010 asset impairment charge), from the calculation of the interest charges coverage ratio required to be maintained under the Cascade Note Purchase Agreement.

The following table provides a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of June 30, 2010:

(in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Lines of Credit and Other Short-Term Debt	$20,994	$121	$46,472	$ 67,587
Senior Unsecured Notes 6.63%, due December 1, 2011	90,000			90,000
Pollution Control Refunding Revenue Bonds, Variable, 3.00% at June 30, 2010, due December 1, 2012	10,400			10,400
9.000% Notes, due December 15, 2016			100,000	100,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000			33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,125			5,125
Senior Unsecured Note 8.89%, due November 30, 2017			50,000	50,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000			30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,390			20,390
	42,000			42,000

Senior Unsecured Notes 6.37%, Series C, due August 20, 2027				
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Obligations of Varistar Corporation - Various up to 13.31% at June 30, 2010		6,084		6,084
Total	$280,915	$6,084	$150,000	$ 436,999
Less:				
Current Maturities	--	734	--	734
Unamortized Debt Discount	--	361	6	367
Total Long-Term Debt	$280,915	$4,989	$149,994	$ 435,898
Total Short-Term and Long-Term Debt (with current maturities)	$301,909	$5,844	$196,466	$ 504,219

11. Class B Stock Options of Subsidiary

In May 2010, options were exercised to purchase 400 IPH Class B common shares at a combined exercise price of $153,000. The book value of the options exercised totaled $681,000 based on an IPH Class B common share value of $2,085.88 per share. The fair value of IPH Class B common shares on the exercise date was $2,485.60 per share. The IPH Class B common shares issued were recorded at their exercise-date fair value of $994,000. The $96,000 net-of-tax difference between the fair value of the shares issued and book-value basis of the options exercised was charged to retained earnings and earnings available for common shares were reduced for both the three and six month periods ended June 30, 2010. In June 2010, the 400 outstanding IPH Class B common shares were repurchased by IPH for $994,000 in cash and retired.

As of June 30, 2010 there were 372 options for the purchase of IPH Class B common shares outstanding with a combined exercise price of $237,000. All 372 outstanding options were “in-the-money” on June 30, 2010. A valuation of IPH Class B common shares in the first quarter of 2010 indicated a fair value of $2,485.60 per share. The book value of outstanding IPH Class B common share options on June 30, 2010 is based on an IPH Class B common share value of $2,085.88 per share.

12. Pension Plan and Other Postretirement Benefits

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2010	2009	2010	2009
Service Cost—Benefit Earned During the Period	$ 1,247	$ 1,133	$ 2,494	$ 2,266
Interest Cost on Projected Benefit Obligation	3,030	2,975	6,060	5,950
Expected Return on Assets	(3,400)	(3,448)	(6,800)	(6,896)
Amortization of Prior-Service Cost	170	181	340	362
Amortization of Net Actuarial Loss	495	5	990	10
Net Periodic Pension Cost	$ 1,542	$ 846	$ 3,084	$ 1,692

The Company did not make a contribution to its pension plan in the six months ended June 30, 2010 and is not currently required to make a contribution in 2010.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2010	2009	2010	2009
Service Cost—Benefit Earned During the Period	$ 165	$ 188	$ 330	$ 376
Interest Cost on Projected Benefit Obligation	418	424	836	848
Amortization of Prior-Service Cost	18	18	36	36

Amortization of Net Actuarial Loss	119	96	238	192
Net Periodic Pension Cost	$ 720	$ 726	$ 1,440	$ 1,452

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2010	2009	2010	2009
Service Cost—Benefit Earned During the Period	$ 425	$ 301	$ 850	$ 602
Interest Cost on Projected Benefit Obligation	775	753	1,550	1,506
Amortization of Transition Obligation	187	187	374	374
Amortization of Prior-Service Cost	50	53	100	106
Amortization of Net Actuarial Loss	188	1	376	2
Effect of Medicare Part D Expected Subsidy	(500)	(297)	(1,000)	(594)
Net Periodic Postretirement Benefit Cost	$ 1,125	$ 998	$ 2,250	$ 1,996

13. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash and Short-Term Investments—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Long-Term Debt—The fair value of the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. The Company’s long-term debt subject to variable interest rates approximates fair value.

	June 30, 2010		December 31, 2009	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ --	$ --	$ 4,432	$ 4,432
Long-Term Debt	(435,898)	(475,179)	(436,170)	(457,907)

15. Income Taxes

The Company's effective income tax rates for the three months ended June 30, 2010 and 2009 were approximately 31.5% and (210.7%), respectively. Only $2.8 million of ShoreMaster’s $12.2 million second quarter 2010 goodwill impairment loss was deductible for income taxes. The Company recorded federal production tax credits (PTCs) and North Dakota wind energy credits totaling approximately $1.9 million in the second of quarter of 2010. In the second quarter of 2009, the Company recorded PTCs and North Dakota wind energy credits totaling approximately $1.8 million on only $0.9 million of income before income taxes, which contributed to the high negative tax rate for the second quarter of 2009.

The Company's effective income tax rates for the six months ended June 30, 2010 and 2009 were approximately 30.5% and (83.2%), respectively. Only $2.8 million of ShoreMaster’s $12.2 million second quarter 2010 goodwill impairment loss was deductible for income taxes. The Company recorded PTCs and North Dakota wind energy credits totaling approximately $3.7 million in the first six months of 2010 and a $1.7 million charge related to the enactment of new federal health care legislation in March 2010. In the first six months of 2009, the Company recorded PTCs and North Dakota wind energy credits totaling $3.9 million on only $3.9 million of income before income taxes, which contributed to the high negative tax rate for the six months ended June 30, 2009.

The Company recognizes PTCs as wind energy is generated and sold based on a per kwh rate prescribed in applicable federal statutes, which may differ significantly from amounts computed, on a quarterly basis, using an overall effective income tax rate anticipated for the full year. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years. The Company utilizes this method of recognizing PTCs for specific reasons, including that PTCs are an integral part of the financial viability of most wind projects and a fundamental component of such wind projects' results of operations.

On May 3, 2010 the Company received a federal income tax refund of $42.3 million related to the carry-back of 2009 net operating losses for tax purposes to prior years.

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

RESULTS OF OPERATIONS

Following is an analysis of our operating results by business segment for the three and six month periods ended June 30, 2010 and 2009, followed by a discussion of changes in our consolidated financial position during the six months ended June 30, 2010 and our expectations for the remainder of 2010.

Comparison of the Three Months Ended June 30, 2010 and 2009

Consolidated operating revenues were $270.2 million for the three months ended June 30, 2010 compared with $246.9 million for the three months ended June 30, 2009. An operating loss of $13.1 million was recorded for the three months ended June 30, 2010 compared with operating income of $6.2 million for the three months ended June 30, 2009. The Company recorded diluted earnings per share of ($0.40) for the three months ended June 30, 2010 compared with $0.07 for the three months ended June 30, 2009.

Asset Impairment Charge—In light of continuing economic uncertainty and delayed economic recovery, ShoreMaster, Inc. (ShoreMaster), the Company’s waterfront equipment business, revised its current sales and operating cash flow projections downward, which resulted in a reassessment of the carrying value of its recorded goodwill. The fair value determination indicated ShoreMaster’s goodwill and other intangible assets were 100% impaired and its long-lived assets were partially impaired, resulting in the following impairment charges in June 2010:

(in thousands)	
Goodwill	$ 12,259
Brand/Trade Name	4,869
Other Intangible Assets	507
Long-Lived Assets	2,105
Total Asset Impairment Charges	$ 19,740

The impact of the impairment losses on second quarter 2010 operating results is shown in the following table:

(in millions, except per share amounts)	Impairment Charges	Consolidated Results
Operating Income (Loss)	$ (19.7)	$ (13.1)
Net Income (Loss)	$ (15.6)	$ (14.2)
Earnings (Loss) Per Share	$ (0.44)	$ (0.40)

Intersegment Eliminations—Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the three month periods ended June 30, 2010 and 2009 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:

Intersegment Eliminations (in thousands)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Operating Revenues:		
Electric	$ 51	$ 53
Nonelectric	1,261	1,149
Cost of Goods Sold	937	1,186
Other Nonelectric Expenses	375	16

Electric

(in thousands)	Three Months Ended June 30, 2010	2009	Change	% Change
Retail Sales Revenues	$ 66,552	$ 61,273	$ 5,279	8.6
Wholesale Revenues – Company Generation	5,201	2,620	2,581	98.5
Net Revenue – Energy Trading Activity	519	792	(273)	(34.5)
Other Revenues	4,012	5,978	(1,966)	(32.9)
Total Operating Revenues	$ 76,284	$ 70,663	$ 5,621	8.0
Production Fuel	16,492	11,754	4,738	40.3
Purchased Power – System Use	10,420	11,877	(1,457)	(12.3)
Other Operation and Maintenance Expenses	29,084	28,959	125	0.4
Depreciation and Amortization	10,038	8,998	1,040	11.6
Property Taxes	2,477	2,255	222	9.8
Operating Income	$ 7,773	$ 6,820	$ 953	14.0

The increase in retail sales revenues mainly is due to the following: (1) a $2.1 million increase in Fuel Clause Adjustment revenues related to a net increase in fuel and purchased power costs incurred to serve retail customers, (2) a $1.6 million increase in renewable resource recovery and transmission rider revenues, (3) a $0.6 million increase in revenues related to a general rate increase in South Dakota which began in May 2009, (4) a $0.5 million revenue refund accrual in the second quarter of 2009 related to North Dakota revenues collected under interim rates, and (5) a 0.4 million increase in Minnesota Conservation Investment Program (CIP) surcharge revenues.

Wholesale electric revenues from company-owned generation increased as a result of a 97.2% increase in wholesale kilowatt-hour (kwh) sales. Generating plant output was 32.4% higher in the second quarter of 2010 than in the second quarter of 2009 when Coyote Station was shut down for six weeks of scheduled maintenance. Net revenue from energy trading activity, including net mark-to-market gains on forward energy contracts, decreased mainly as a result of a decrease in net mark-to-market gains recognized on forward purchases and sales of electricity between the quarters. The decrease in other electric revenues reflects a $2.5 million decrease in revenues from contracted services, partially offset by a $0.6 million increase in transmission services revenue.

The increase in fuel costs is due to a 32.4% increase in kwhs generated from Otter Tail Power Company's (OTP's) steam-powered and combustion turbine generators. Purchased power costs decreased as a result of a 31.6% decrease in kwhs purchased for retail sales, partially offset by a 28.3% increase in the cost per kwh purchased. Both the increase in kwhs generated and the decrease in kwhs purchased were driven by the increased availability of Coyote Station in the second quarter of 2010.

The increase in other operation and maintenance expenses includes an increase in labor costs of $1.7 million, mainly related to increased wage and benefit costs, offset by a $1.4 million decrease in costs incurred to provide contracted services to others.

The increase in depreciation expense is mainly due to the addition of 33 wind turbines at the Luverne Wind Farm that were placed in service in September 2009.

Plastics

(in thousands)	Three Months Ended June 30, 2010	2009	Change	% Change
Operating Revenues	$ 26,739	$ 22,183	$ 4,556	20.5
Cost of Goods Sold	23,942	19,679	4,263	21.7
Operating Expenses	1,225	1,136	89	7.8
Depreciation and Amortization	778	717	61	8.5
Operating Income	$ 794	$ 651	$ 143	22.0

Operating revenues for the plastics segment increased as result of a 23.9% increase in the price per pound of polyvinyl chloride (PVC) pipe sold, partially offset by a 2.7% decrease in pounds of PVC pipe sold. The cost per pound of PVC pipe sold increased 25.1% between the quarters.

Manufacturing

(in thousands)	Three Months Ended June 30, 2010	2009	Change	% Change
Operating Revenues	$ 84,411	$ 76,843	$ 7,568	9.8
Cost of Goods Sold	68,610	59,908	8,702	14.5
Other Operating Expenses	11,122	10,364	758	7.3
Asset Impairment Charge	19,740	--	19,740	--
Depreciation and Amortization	5,843	5,666	177	3.1
Operating (Loss) Income	$ (20,904)	$ 905	$ (21,809)	--

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

- Revenues at BTD Manufacturing, Inc. (BTD) increased $7.1 million due to improved customer demand, better productivity and higher scrap-metal prices.
- Revenues at DMI Industries, Inc. (DMI) increased $1.1 million on increased production. In the second quarter of 2009, DMI reduced production to balance output with lower industry and customer demand.
- Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $1.0 million due to increased sales of custom and horticultural products.
-

Revenues at ShoreMaster decreased $1.6 million due to a $2.6 million decrease in commercial sales which have been hit hard by the recent recession and are not showing signs of recovery, partially offset by a $1.1 million increase in sales of residential products.

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

- Cost of goods sold at DMI increased $5.7 million, mainly as a result of incurring $2.9 million in additional production costs to manufacture towers to a customer's new design specifications, but also due to increased production.
- Cost of goods sold at BTD increased $3.8 million as a result of increased sales volumes.
- Cost of goods sold at T.O. Plastics increased $0.7 million as a result of increased sales volumes.
- Cost of goods sold at ShoreMaster decreased $1.5 million due to the decrease in sales of commercial products.

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

- Other operating expenses at ShoreMaster increased $1.0 million, reflecting a $1.4 million increase in expense related to an increase in allowance for doubtful accounts in the residential and commercial businesses, offset by a $0.3 million reduction in salaries and selling expenses.

- Other operating expenses at T.O. Plastics increased $0.1 million mainly due to increases in promotional and other sales related expenses.

- Other operating expenses at DMI decreased $0.1 million between the quarters.

- Other operating expenses at BTD decreased $0.2 million, mainly due to decreases in contracted services and outside sales commissions.

As discussed above, ShoreMaster recorded $19.7 million in asset impairment charges in June 2010.

Depreciation expense increased as a result of 2009 capital additions, mainly at DMI and BTD.

Health Services

	Three Months Ended June 30,			%
(in thousands)	2010	2009	Change	Change
Operating Revenues	$ 23,645	$ 28,192	$ (4,547)	(16.1)
Cost of Goods Sold	18,038	22,431	(4,393)	(19.6)
Operating Expenses	4,146	4,871	(725)	(14.9)
Depreciation and Amortization	1,252	972	280	28.8
Operating Income (Loss)	$ 209	$ (82)	$ 291	354.9

Revenues from scanning and other related services decreased $3.8 million as a result of a 21.9% decrease in scans performed, partially offset by a 2.6% increase in revenue per scan. Revenues from equipment sales and servicing decreased $0.7 million. The decrease in costs of goods sold reflects a $2.0 million reduction in material, labor and other direct costs of sales and a reduction in equipment rental costs of $2.4 million directly related to efforts by the health services segment to right-size its fleet of imaging assets by exercising purchase options on productive imaging assets coming off lease in 2010 and not renewing leases on underutilized imaging assets coming off lease. Through this process, the imaging business has reduced the combined number of units of imaging equipment it leases and owns by 12.4% over the past twelve months. The decrease in operating expenses includes $0.4 million related to an increase in gains on sales of assets and a $0.3 million reduction in sales and marketing salaries and expenses. The increase in depreciation expense reflects an increase in owned equipment compared with the same quarter a year ago.

Food Ingredient Processing

	Three Months Ended June 30,	%

(in thousands)	2010	2009	Change	Change
Operating Revenues	$ 18,255	$ 20,581	$ (2,326)	(11.3)
Cost of Goods Sold	13,114	14,781	(1,667)	(11.3)
Operating Expenses	922	787	135	17.2
Depreciation and Amortization	1,217	1,067	150	14.1
Operating Income	$ 3,002	$ 3,946	$ (944)	(23.9)

The decrease in food ingredient processing revenues is due to an 8.1% decrease in pounds of product sold, combined with a 3.5% decrease in the price per pound of product sold. Cost of goods sold decreased as a result of a 3.5% decrease in the cost per pound of product sold mainly due to a decrease in raw potato costs. The increase in operating expenses is mainly due to salary cost increases.

Other Business Operations

(in thousands)	Three Months Ended June 30, 2010	2009	Change	% Change
Operating Revenues	$ 42,173	$ 29,597	$ 12,576	42.5
Cost of Goods Sold	27,359	19,706	7,653	38.8
Operating Expenses	14,196	11,577	2,619	22.6
Depreciation and Amortization	621	586	35	6.0
Operating Loss	$ (3)	$ (2,272)	$ 2,269	99.9

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

- Revenues at Foley Company increased $8.5 million mainly due to the initiation of work on a few large projects in the second quarter of 2010.

- Revenues at E.W. Wylie Corporation (Wylie) increased $4.0 million as a result of a 17.9% increase in miles driven by company-owned and owner-operated trucks combined with a 24.5% increase in revenue per mile driven and a $0.7 million increase in revenue from brokerage activity. The revenue increase also reflects price increases related to a 28.5% increase in the average cost per gallon of fuel consumed.

- Revenues at Aevenia, Inc. (Aevenia) increased $0.1 million between the quarters.

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

- Cost of goods sold at Foley Company increased $7.8 million as a result of an increase in the size and volume of jobs in progress in 2010.

- Cost of goods sold at Aevenia decreased $0.2 million, reflecting a reduction in direct labor costs.

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

- Operating expenses at Wylie increased $2.5 million as a result of increases of $1.1 million in contractor and brokerage settlements, $0.8 million in fuel costs and $0.5 million in labor costs. These expense increases were due to the 17.9% increase in miles driven by company-owned and owner-operated trucks combined with a 28.5% increase in the average cost per gallon of fuel consumed and a 16.8% increase in brokerage miles.

- Operating expenses at Foley Company increased $0.2 million between the quarters mainly for salaries and operating supplies.

- Operating expenses at Aevenia decreased $0.1 million between the quarters.

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 June 30,			
(in thousands)	2010	2009	Change	% Change
Operating Expenses	$ 3,880	$ 3,691	$ 189	4.8
Depreciation and Amortization	134	97	37	38.1

The increase in corporate operating expenses reflects an increase in expenditures for contracted services.

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Other Income

Other income increased $0.4 million in the second quarter of 2010 compared with the second quarter of 2009 as a result of $1.3 million in Minnesota CIP accrued incentives at OTP, offset by a $0.9 million decrease in allowance for equity funds used during construction related to a decrease in construction work in progress at OTP.

Interest Charges

Interest charges increased $2.8 million in the second quarter of 2010 compared with the second quarter of 2009 as a result of a $60.7 million increase in the average balance of long-term debt outstanding combined with an increase in the average rate of interest paid on outstanding long-term debt between the quarters, a $0.3 million reduction in capitalized interest related to a reduction in construction work in progress at OTP, and a $0.2 million increase in debt issuance reacquisition loss amortization expenses related to recent debt issuances, retirements and borrowing agreement amendments. The December 2009 debt offering of $100 million 9.000% Notes due 2016 contributed $2.2 million to the increase in interest expenses between the quarters.

Income Taxes

Income taxes decreased $4.7 million in the second quarter of 2010 compared with the second quarter of 2009 as a result of a $21.6 million decrease in income before income taxes. Our effective income tax rates for the three months ended June 30, 2010 and 2009 were approximately 31.5% and (210.7%), respectively. Only $2.8 million of ShoreMaster’s $12.2 million second quarter 2010 goodwill impairment loss was deductible for income taxes. We recorded federal production tax credits (PTCs) and North Dakota wind energy credits totaling approximately $1.9 million in the second of quarter of 2010. In the second quarter of 2009, we recorded PTCs and North Dakota wind energy credits totaling approximately $1.8 million on only $0.9 million of income before income taxes, which contributed to the high negative tax rate for the second quarter of 2009 quarter. PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Comparison of the Six Months Ended June 30, 2010 and 2009

Consolidated operating revenues were $532.4 million for the six months ended June 30, 2010 compared with $524.1 million for the six months ended June 30, 2009. Operating income was $2.8 million for the six months ended June 30, 2010 compared with $14.8 million for the six months ended June 30, 2009. The Company recorded diluted earnings per share of ($0.28) for the six months ended June 30, 2010 compared to $0.19 for the six months ended June 30, 2009.

Asset Impairment Charge—The impact of the ShoreMaster impairment charges discussed above on operating results for the six months ended June 30, 2010 is shown in the following table:

(in millions, except per share amounts)	Impairment Charges	Consolidated Results
Operating Income (Loss)	$ (19.7)	$ 2.8
Net Income (Loss)	$ (15.6)	$ (9.5)
Earnings (Loss) Per	$ (0.44)	$ (0.28)

Share

Intersegment Eliminations—Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the six month periods ended June 30, 2010 and 2009 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:

Intersegment Eliminations (in thousands)	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating Revenues:		
Electric	$ 123	$ 115
Nonelectric	2,142	2,086
Cost of Goods Sold	1,688	2,026
Other Nonelectric Expenses	577	175

Electric

(in thousands)	Six Months Ended June 30, 2010	2009	Change	% Change
Retail Sales Revenues	$ 147,565	$ 140,328	$ 7,237	5.2
Wholesale Revenues – Company Generation	9,193	7,024	2,169	30.9
Net Revenue – Energy Trading Activity	2,526	2,185	341	15.6
Other Revenues	8,086	9,667	(1,581)	(16.4)
Total Operating Revenues	$ 167,370	$ 159,204	$ 8,166	5.1
Production Fuel	37,401	30,413	6,988	23.0
Purchased Power – System Use	22,476	29,250	(6,774)	(23.2)
Other Operation and Maintenance Expenses	57,406	55,889	1,517	2.7
Depreciation and Amortization	20,075	17,986	2,089	11.6
Property Taxes	4,951	4,745	206	4.3
Operating Income	$ 25,061	$ 20,921	$ 4,140	19.8

The increase in retail sales revenues mainly is due to the following: (1) a $2.5 million increase in Minnesota renewable resource recovery and transmission rider revenues, (2) a $1.5 million increase in North Dakota renewable resource recovery rider revenues, (3) a $1.5 million increase in revenues related to a general rate increase in South Dakota which began in May 2009, (4) a $0.9 million increase in Minnesota CIP surcharge revenues, and (5) an additional Minnesota interim rate refund accrual of $0.5 million in the first quarter of 2009.

Wholesale electric revenues from company-owned generation increased as a result of a 37.1% increase in wholesale kwh sales, partially offset by a 4.5% decrease in the average price per kwh sold. Generating plant output was 18.8% higher in the first six months of 2010 than in the first six months of 2009, mainly as a result of Coyote Station being shut down for six weeks of scheduled maintenance in the second quarter of 2009. Net revenue from energy trading activity, including net mark-to-market gains on forward energy contracts, increased mainly as a result of an increase in net mark-to-market gains recognized on forward purchases and sales of electricity entered into in the first quarter of 2010 and scheduled for settlement in the second and third quarters of 2010. The decrease in other electric revenues reflects a $2.5 million decrease in revenues from contracted services, partially offset by a $0.9 million increase in transmission services revenue.

The increase in fuel costs is due to an 18.8% increase in kwhs generated from OTP’s fuel-fired plants combined with a 3.5% increase in the cost of fuel per kwh generated. The decrease in purchased power – system use is due to a 38.5% decrease in kwhs purchased for retail sales, partially offset by a 25.0% increase in the cost per kwh purchased. Both the increase in kwhs generated and the decrease in kwhs purchased were driven by the increased availability of Coyote Station in the second quarter of 2010.

The increase in other operation and maintenance expenses includes an increase in labor costs of $2.1 million, mainly related to increased wage and benefit costs and a decrease in capitalized labor between the periods, and an increase in Minnesota CIP recognized program costs of $0.9 million, offset by a $1.5 million decrease in costs incurred to provide contracted services to others.

The increase in depreciation expense is mainly due to the addition of 33 wind turbines at the Luverne Wind Farm that were placed in service in September 2009.

Plastics

(in thousands)	Six Months Ended June 30, 2010	2009	Change	% Change
Operating Revenues	$ 49,826	$ 35,713	$ 14,113	39.5
Cost of Goods Sold	43,432	35,031	8,401	24.0
Operating Expenses	2,422	2,511	(89)	(3.5)
Depreciation and Amortization	1,559	1,433	126	8.8
Operating Income (Loss)	$ 2,413	$ (3,262)	$ 5,675	174.0

Operating revenues for the plastics segment increased as result of a 14.5% increase in pounds of PVC pipe sold combined with a 22.0% increase in the price per pound of PVC pipe sold. The increase in costs of goods sold was related to the increase in pounds of PVC pipe sold combined with an 8.3% increase in the cost per pound of pipe sold. The increased profitability between the periods was also impacted by the sell-off of higher priced finished goods inventory in the first quarter of 2009.

Manufacturing

(in thousands)	Six Months Ended June 30, 2010	2009	Change	% Change
Operating Revenues	$ 162,989	$ 172,862	$ (9,873)	(5.7)
Cost of Goods Sold	130,568	139,443	(8,875)	(6.4)
Other Operating Expenses	19,591	20,410	(819)	(4.0)
Asset Impairment Charge	19,740	--	19,740	--
Product Recall and Testing Costs	--	1,766	(1,766)	--
Depreciation and Amortization	11,664	11,024	640	5.8
Operating (Loss) Income	$ (18,574)	$ 219	$ (18,793)	--

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

- Revenues at DMI decreased $7.8 million as production activity has been reduced to match lower industry and customer demand.

- Revenues at ShoreMaster decreased $5.9 million due to a decrease in commercial sales which have been hit hard by the recent economic recession and are not showing signs of recovery.

- Revenues at BTD increased $2.4 million due to improved customer demand, better productivity and higher scrap-metal prices.

- Revenues at T.O. Plastics increased $1.5 million due to increased sales of custom and horticultural products.

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

- Cost of goods sold at ShoreMaster decreased $5.3 million mainly due to the decrease in sales of commercial products and $0.9 million in additional costs incurred on a commercial project in the first quarter of 2009.

- Cost of goods sold at DMI decreased $3.0 million as a result of decreased production levels. The reduction in costs related to production decreases were partially offset by $2.9 million in additional production costs incurred in the second quarter of 2010 to manufacture towers to a customer's new design specifications.

- Cost of goods sold at BTD decreased $1.3 million mainly as a result of a $1.0 million reduction in the price of finished goods inventory recorded in the first quarter of 2009 but also due to improved productivity in 2010.

- Cost of goods sold at T.O. Plastics increased $0.8 million as a result of increased sales of custom and horticultural products.

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

- Other operating expenses at DMI decreased $0.7 million as a result of decreases in employee costs and reductions in insurance expenses related to safety improvements. The decrease also reflects a $0.2 million loss on an asset sale in the first quarter of 2009.

- Other operating expenses at BTD decreased $0.6 million as a result of costs incurred in the first six months of 2009 to implement a management program designed to improve productivity across the organization. No similar costs were incurred in the first six months of 2010.

- Other operating expenses at ShoreMaster decreased $0.1 million between the periods.

- Other operating expenses at T.O. Plastics increased $0.4 million mainly due to increased salary and benefit costs related to new hires in engineering and sales positions and to an increase in promotional expenses.

As discussed above, ShoreMaster recorded $19.7 million in asset impairment charges in June 2010. ShoreMaster's first quarter 2009 expenses included $1.4 million in costs related to the recall of certain trampoline products and $0.4 million in costs to test imported products for lead/phthalate content.

Depreciation expense increased as a result of 2009 capital additions, mainly at DMI and BTD.

Health Services

(in thousands)	Six Months Ended June 30, 2010	2009	Change	% Change
Operating Revenues	$ 48,816	$ 56,359	$ (7,543)	(13.4)
Cost of Goods Sold	38,404	44,568	(6,164)	(13.8)
Operating Expenses	8,762	9,960	(1,198)	(12.0)
Depreciation and Amortization	2,356	1,962	394	20.1
Operating Loss	$ (706)	$ (131)	$ (575)	--

Revenues from scanning and other related services decreased $7.4 million as a result of a 15.7% decrease in scans performed combined with a 1.5% decrease in revenue per scan. Revenues from equipment sales and servicing decreased $0.1 million between the periods. The decrease in costs of goods sold reflects a $1.9 million reduction in material, labor and other direct costs of sales and a reduction in equipment rental costs of $4.2 million directly related to efforts by the health services segment to right-size its fleet of imaging assets by exercising purchase options on productive imaging assets coming off lease in 2010 and not renewing leases on underutilized imaging assets coming off lease. Through this process, the imaging business has reduced the combined number of units of imaging equipment it leases and owns by 12.4% over the past twelve months. The decrease in operating expenses includes $0.6 million related to an increase in gains on sales assets and a $0.5 million reduction in sales and marketing salaries and expenses. The increase in depreciation expense reflects an increase in owned equipment related to the purchase of assets with value coming off lease.

Food Ingredient Processing

(in thousands)	Six Months Ended June 30, 2010	2009	Change	% Change
Operating Revenues	$ 37,170	$ 40,667	$ (3,497)	(8.6)
Cost of Goods Sold	27,542	30,763	(3,221)	(10.5)
Operating Expenses	1,864	1,599	265	16.6
Depreciation and Amortization	2,384	2,108	276	13.1
Operating Income	$ 5,380	$ 6,197	$ (817)	(13.2)

The decrease in food ingredient processing revenues is due to a 4.2% decrease in pounds of product sold, combined with a 4.6% decrease in the price per pound of product sold. The decrease in cost of goods sold reflects a 6.5% decrease in the cost per pound of product sold mainly due to a decrease in raw potato costs. The increase in operating expenses is mainly due to salary and benefit cost increases. The increase in depreciation expense is related to 2009 and 2010 capital additions.

Other Business Operations

(in thousands)	Six Months Ended June 30, 2010	2009	Change	% Change
Operating Revenues	$ 68,475	$ 61,492	$ 6,983	11.4
Cost of Goods Sold	43,780	40,501	3,279	8.1
Operating Expenses	26,713	22,438	4,275	19.1
Depreciation and Amortization	1,318	1,210	108	8.9
Operating Loss	$ (3,336)	$ (2,657)	$ (679)	(25.6)

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

- Revenues at Wylie increased $5.6 million as a result of a 25.4% increase in miles driven by company-owned and owner-operated trucks combined with a 9.2% increase in revenue per mile driven and a $0.7 million increase in revenue from brokerage activity. The revenue increase also reflects price increases related to a 33.5% increase in the average cost per gallon of fuel consumed.

- Revenues at Foley Company increased $2.2 million due to the initiation of work on a few large projects in the second quarter of 2010.

- Revenues at Aevenia decreased $0.8 million as a result of a reduction in work volume.

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

- Cost of goods sold at Foley Company increased $4.1 million as a result of an increase in the size and volume of jobs in progress in 2010.

- Cost of goods sold at Aevenia decreased $0.8 million, mainly due to a decrease in direct labor costs related to a reduction of jobs in progress.

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

- Operating expenses at Wylie increased $3.9 million as a result of increases of $1.9 million in contractor and brokerage settlements, $1.0 million in labor costs, $0.6 million in fuel costs and $0.5 million in repairs and maintenance costs. These expense increases were due to the 25.4% increase in miles driven by company-owned and owner-operated trucks combined with a 33.5% increase in the average cost per gallon of fuel consumed and a 10.0% increase in brokerage miles.

- Operating expenses at Foley Company increased $0.5 million between the periods mainly for salaries, maintenance and supplies.

- Operating expenses at Aevenia decreased $0.1 million due to a reduction in labor and benefit costs.

Corporate

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

	Six Months Ended June 30,			%
(in thousands)	2010	2009	Change	Change
Operating Expenses	$ 7,112	$ 6,301	$ 811	12.9
Depreciation and Amortization	278	197	81	41.1

The increase in corporate operating expenses reflects increased expenses for employee benefits and contracted services.

Other Income

Other income decreased $0.1 million in the first six months of 2010 compared with the first six months of 2009 as a $1.7 million increase in Minnesota CIP accrued incentives at OTP was offset by (1) a $1.0 million decrease in allowance for equity funds used during construction related to a decrease in construction work in progress at OTP and (2) a $0.8 million increase in foreign currency transaction losses incurred in the Canadian operations of DMI and Idaho Pacific Holdings, Inc. (IPH) related to fluctuations in foreign currency exchange rates between the Canadian and U.S. dollar.

Interest Charges

Interest charges increased $5.5 million in the first six months of 2010 compared with the first six months of 2009 as a result of a $60.3 million increase in the average balance of long-term debt outstanding combined with an increase in the average rate of interest paid on outstanding long-term debt between the periods, a $0.7 million reduction in capitalized interest related to a reduction in construction work in progress at OTP, and a $0.6 million increase in debt issuance and reacquisition loss amortization expenses related to recent debt issuances, retirements and borrowing agreement amendments. The December 2009 debt offering of $100 million 9.000% Notes due 2016 contributed $4.5 million to the increase in interest expenses between the periods.

Income Taxes

Income taxes decreased $0.9 million in the first six months of 2010 compared with the first six months of 2009, mainly as a result of an $8.0 million decrease in taxable income, partially offset by a charge of $1.7 million in the first quarter of 2010 related to the enactment of new federal health care legislation and a $0.2 million decrease in PTCs and North Dakota wind energy credits related to OTP’s wind projects.

Our effective income tax rates for the six months ended June 30, 2010 and 2009 were approximately 30.5% and (83.3%), respectively. Only $2.8 million of ShoreMaster’s $12.2 million second quarter 2010 goodwill impairment loss was deductible for income taxes. We recorded PTCs and North Dakota wind energy credits totaling approximately $3.7 million in the first six months of 2010 and a $1.7 million charge related to the enactment of new federal health care legislation in March 2010. In the first six months of 2009, we recorded PTCs and North Dakota wind energy credits totaling $3.9 million on only $3.9 million of income before income taxes, which contributed to the high negative tax rate for the six months ended June 30, 2009. PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

FINANCIAL POSITION

The following table presents the status of our lines of credit as of June 30, 2010 and December 31, 2009:

(in thousands)	Line Limit	In Use on June 30, 2010	Restricted due to Outstanding Letters of Credit	Available on June 30, 2010	Available on December 31, 2009
Otter Tail Corporation Credit Agreement	$ 200,000	$ 46,472	$ 14,024	$ 139,504	$ 179,755
OTP Credit Agreement	170,000	20,994	250	148,756	167,735
Total	$ 370,000	$ 67,466	$ 14,274	$ 288,260	$ 347,490

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if current market conditions continue. Our balance sheet is strong and we are in compliance with our debt covenants. Our dividend payout ratio for the year ended December 31, 2009 was 168% compared to 108% and 66% for the years ended December 31, 2008 and 2007, respectively. Our current indicated annual dividend would result in a dividend per share of $1.19 in 2010. The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, cash flows from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, solid credit ratings, and alternative financing arrangements such as leasing. We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. Equity or debt financing will be required in the period 2011 through 2014 given the expansion plans related to our electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit, refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes.

DMI is party to a $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement expires in March 2011. Accounts receivable totaling $29.3 million were sold in the first six months of 2010. Discounts, fees and commissions charged to operating expense for the six months ended June 30, 2010 and 2009 were $107,000 and $267,000, respectively. The balance of receivables sold that was outstanding to the buyer as of June 30, 2010 was $6.4 million. The sales of these accounts receivable are reflected as a reduction of accounts receivable in our consolidated balance sheets and the proceeds are included in the cash flows from operating activities in our consolidated statement of cash flows.

Cash provided by operating activities was $49.4 million for the six months ended June 30, 2010 compared with cash provided by operating activities of $90.3 million for the six months ended June 30, 2009. The $40.9 million decrease in operating cash flows is mainly due to a net increase in working capital of $10.8 million in the first half of 2010 compared with a net decrease in working capital of $35.2 million in the first half of 2009. In the first half of 2009, working capital decreased as a result of, and in response to, the economic recession as sales, accounts receivable and costs in excess of billings were declining and inventories were being reduced. In the first half of 2010, accounts receivable and costs in excess of billings increased and inventories increased slightly in response to improving sales at some of our operating companies. On May 3, 2010 we received a federal income tax refund of $42.3 million related to the carry-back of 2009 net operating losses for tax purposes to prior years, which was the main contributing factor to the $35.9 million decrease in interest payable and income taxes receivable in the first half of 2010.

Net cash used in investing activities was $38.4 million for the six months ended June 30, 2010 compared with $120.0 million for the six months ended June 30, 2009. Cash used for capital expenditures decreased by $18.4 million between the periods mainly due to a decrease in capital expenditures of $18.1 million in the electric segment related to second quarter 2009 Luverne Wind Farm expenditures. Capital expenditure decreases in the manufacturing segment of $12.0 million, mainly related to capital additions at DMI and BTD in the first half of 2009, were mostly offset by a $10.7 million increase in capital expenditures in the health services segment. Capital expenditures in the first half of 2010 include $17.7 million at OTP for expenditures across all plant categories and $12.2 million in the health services segment mainly for the purchase of imaging assets coming off lease.

Net cash used in financing activities was $15.6 million for the six months ended June 30, 2010 compared with net cash provided by financing activities of $31.6 million for the six months ended June 30, 2009. Proceeds from short-term borrowings and checks written in excess of cash of $67.2 million in the first half of 2010 compared to a net reduction in short-term borrowings of $15.0 million in the first half of 2009. Proceeds from the issuance of long-term debt were $0.1 million in the first half of 2010 compared with $75.0 million in the first half of 2009 used to finance construction of 33 wind turbines at the Luverne Wind Farm. We paid $58.7 million to retire long-term debt in the first half of 2010 compared to $5.4 million in the first half of 2009. Proceeds from short-term borrowings and checks written in excess of cash of $67.2 million in the first six months of 2010 were used to retire early a portion of $58 million in long-term debt used to finance construction of 33 wind turbines at the Luverne Wind Farm and to finance capital expenditures in the first half of 2010.

Our contractual obligations reported in the table on page 53 of our Annual Report on Form 10-K for the year ended December 31, 2009 have increased by $37.2 million: Our "Operating Lease Obligations" have increased by $0.2 million for 2010 and $1.1 million for 2011 and 2012 related to an agreement to renew a lease for rail cars to transport coal to Hoot Lake Plant from September 2010 through August 2012. Our "Coal Contracts (required minimums)" have increased by $2.9 million in 2010 and $33.0 million in 2011 and 2012 related to a coal supply agreement to cover a portion of coal requirements at OTP's Big Stone Plant.

Our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

On May 11, 2009 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. On March 17, 2010, we entered into a Distribution Agreement (the Agreement) with J.P. Morgan Securities Inc. (JPMS). Pursuant to the terms of the Agreement, we may offer and sell our common shares from time to time through JPMS, as our distribution agent for the offer and sale of the shares, up to an aggregate sales price of $75,000,000. Under the Agreement, we will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. We are not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement. The shares, if issued, will be issued pursuant to our shelf registration statement, as amended. No shares have been sold pursuant to the agreement.

On May 4, 2010 we entered into a $200 million Second Amended and Restated Credit Agreement (the Credit Agreement) with the banks named therein, including U.S. Bank National Association, a national banking association, as administrative agent for the Banks and as Lead Arranger, Bank of America, N.A. and JPMorgan Chase Bank, National Association, as Co-Syndication Agents, and KeyBank National Association, as Documentation Agent. The Credit Agreement amends and restates our $200 million credit agreement dated as of December 23, 2008, and is an unsecured revolving credit facility that we can draw on to support our nonelectric operations. Borrowings under the Credit Agreement bear interest at LIBOR plus 3.25%, subject to adjustment based on our senior unsecured credit ratings. The Credit Agreement expires on May 4, 2013. The Credit Agreement contains a number of restrictions on us and 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 Credit Agreement also contains affirmative covenants and events of default. The

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. Our obligations under the Credit Agreement are guaranteed by Varistar and its material subsidiaries. Outstanding letters of credit issued by us under the Credit Agreement can reduce the amount available for borrowing under the line by up to $50 million. The Credit Agreement has an accordion feature whereby the line can be increased to $250 million as described in the Credit Agreement.

OTP is the borrower under the $170 million credit agreement referred to in the table above (the OTP Credit Agreement) with an accordion feature whereby the line can be increased to $250 million as described in the OTP Credit Agreement. The credit agreement was entered into between OTP 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 OTP Credit Agreement is an unsecured revolving credit facility that OTP 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 borrower's senior unsecured debt. The OTP Credit Agreement contains a number of restrictions on the business of OTP, 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 OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the borrower's credit ratings. The OTP Credit Agreement is subject to renewal on July 30, 2011. The OTP Credit Agreement is an obligation of OTP.

In November 2009, OTP paid down $17 million of its two-year, $75 million term loan, originally due May 11, 2011. OTP paid off the remaining $58 million balance in January 2010 using lower cost funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayments and retirement of this debt.

On May 3, 2010 we received a federal income tax refund of $42.3 million related to the carry-back of 2009 net operating losses for tax purposes to prior years. The majority of these funds were used to repay borrowings under the OTP Credit Agreement.

The note purchase agreement relating to the $90 million 6.63% senior notes due December 1, 2011, as amended (the 2001 Note Purchase Agreement), the note purchase agreement relating to the $50 million 8.89% senior note due November 30, 2017, as amended (the Cascade Note Purchase Agreement), and the note purchase agreement relating to the $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037, as amended (the 2007 Note Purchase Agreement) each states that the applicable obligor 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 the applicable obligor 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 the applicable obligor 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 such obligor. The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement each contain a number of restrictions on the applicable obligor and its subsidiaries. These include restrictions on the obligor's ability and the ability of the obligor's 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. Our obligations under the Cascade Note Purchase Agreement remain guaranteed by Varistar and certain of its material subsidiaries.

On June 23, 2010 we entered into Amendment No. 3 to our Note Purchase Agreement dated as of February 23, 2007 with Cascade Investment, L.L.C., as amended (the Cascade Note Purchase Agreement). Amendment No. 3 amends certain covenants and related definitions contained in the Cascade Note Purchase Agreement to, among other things, provide us and our material subsidiaries with additional flexibility to incur certain customary liens, make certain investments, and give certain guaranties, in each case under the circumstances set forth in Amendment No. 3. On July 29, 2010 we entered into Amendment No. 4 to the Cascade Note Purchase Agreement, which was effective June 30, 2010. The amendments contained in Amendment No. 4 permit us to exclude impairment charges and write-offs of assets (including ShoreMaster's June 2010 asset impairment charge), from the calculation of the interest charges coverage ratio required to be maintained under the Cascade Note Purchase Agreement.

Financial Covenants

As of June 30, 2010 the Company was in compliance with the financial statement covenants that existed in its debt agreements.

None of the Credit and Note Purchase Agreements contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

Our borrowing agreements are subject to certain financial covenants. Specifically:

- Under the Credit Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Credit Agreement.

- Under the Cascade Note Purchase Agreement, we may not permit our ratio of Consolidated Debt to Consolidated Total Capitalization to be greater than 0.60 to 1.00 or our Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the ratio of OTP's Debt to OTP's Total Capitalization to be greater than 0.60 to 1.00, or permit Priority Debt to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement.

- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the OTP Credit Agreement.

- Under the 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio (or, in the case of the 2001 Note Purchase Agreement, its Interest Charges Coverage Ratio) to be less than 1.50 to 1.00, in each case as provided in the related borrowing or insurance agreement. In addition, under the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement, OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.

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

2010 EXPECTATIONS

The statements in this section are based on our current outlook for 2010 and are subject to risks and uncertainties described under "Forward Looking Information – Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995."

We are revising our 2010 diluted earnings per share guidance from our previously announced range of $1.00 to $1.40 to be in the range of $0.70 to $1.00, which is before the $0.49 per share effect of the asset impairment charge recorded this quarter and the health care reform charge recorded in the first quarter of 2010. On a GAAP basis the range will be $0.21 to $0.51 per share including the effect of the health care reform charge and the asset impairment charge. This guidance reflects challenges presented by current economic conditions, as well as our plans and strategies for improving operating results as the economy recovers. Our current consolidated capital expenditures expectation for 2010 is in the range of $80 million to $90 million. This compares with $177 million of capital expenditures in 2009. We continue to explore investments in generation and transmission projects for the electric segment that could have a positive impact on our earnings and returns on capital in the future.

Expected Range of Earnings (Loss) Per Share:

Electric*	$0.89	to	$0.96
Plastics	$0.02	to	$0.04
Manufacturing**	($0.05)	to	$0.05

Health Services	$0.00 to $0.02
Food Ingredient Processing	$0.16 to $0.19
Other Business Operations	($0.01) to $0.03
Corporate	($0.31) to ($0.29)

*The electric earnings (loss) per share guidance ranges from $0.84 to $0.91 on a GAAP basis, which includes the effect of the $0.05 per share impact of the health care reform charge.

**The manufacturing segment earnings (loss) per share guidance ranges from ($0.49) to ($0.39) on a GAAP basis, which includes the effect of the $0.44 per share impact of the asset impairment charge.

Comparison of GAAP to NonGAAP Financial Measures—NonGAAP financial measurements are provided here to assist in understanding the impact of certain asset impairment costs. We believe that adjusting for certain one-time costs will assist investors in making an evaluation of our performance. This information should not be construed as an alternative to the reported results, which have been determined in accordance with accounting principles generally accepted in the United States of America.

Contributing to the revised earnings guidance for 2010 are the following:

- We expect a slightly lower level of net income from our electric segment in 2010 compared with 2009. This decrease is due to continued soft wholesale power markets, lower AFUDC earnings as there are no large construction projects expected this year and increased operating and maintenance expense in 2010 due primarily to higher employee benefit costs. Expectations for 2010 reflect an interim rate increase of approximately $2.9 million in revenue in the Minnesota jurisdiction. OTP's request for an interim rate increase of 3.8%, approximately $5.0 million in annual revenue, was approved effective June 1, 2010. Its final overall rate increase request of 8.0%, approximately $10.6 million in annual revenue is pending approval.

- We expect our plastics segment's 2010 earnings to be in a range from $0.7 million to $1.5 million.

- We now expect to be slightly profitable in our manufacturing segment in 2010. This is before the effect of the asset impairment charge recorded at ShoreMaster.

  - We expect improved earnings at BTD in 2010 due to increased revenue in 2010 and productivity improvements and cost reductions made in 2009.

  - We now expect ShoreMaster to have a net loss in 2010 as the business continues to be affected by current depressed economic conditions and does not expect an improvement to overall business conditions until later in the economic recovery cycle.

  - We now expect DMI to have a net loss in 2010. This is primarily driven by lower business volumes for the year than projected, resulting from a deferral of deliveries for one contract into 2011 and from lower order intake than projected as a result of lower demand for towers than anticipated. The American Wind Energy Association reports year-to-date wind installations through June 2010 to be 71% below June 2009 year-to-date installations. It is also due to additional production costs related to the previously mentioned start of production of a customer's new tower design.

  - We expect slightly better earnings at T. O. Plastics in 2010 compared with 2009.

  - Backlog in place in the manufacturing segment is approximately $114 million for the remainder of 2010 compared with $92 million one year ago.

- We expect increased net income from our health services segment in 2010. In an effort to right-size its fleet of imaging assets, health services is not renewing leases on a large number of imaging assets that come off lease in 2010, which will result in a lower level of rental costs in 2010.

- We expect net income from our food ingredient processing business to be in the range of $5.5 million to $7.0 million in 2010.

- We expect our other business operations segment to have improved earnings in 2010 compared with 2009. Backlog in place for the construction businesses is $65 million for the remainder of 2010 compared with $42 million one year ago.

- We expect corporate general and administrative costs to return to more normal levels in 2010.

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, unbilled electric revenues, accrued renewable resource and transmission rider revenues, valuations of forward energy contracts, 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 58 through 62 of our Annual Report on Form 10-K for the year ended December 31, 2009. There were no material changes in critical accounting policies or estimates during the quarter ended June 30, 2010, except as noted below.

GOODWILL IMPAIRMENT

We account for goodwill and other intangible assets in accordance with the requirements of ASC 350, Intangibles—Goodwill and Other, requiring goodwill and indefinite-lived intangible assets to be measured for impairment at least annually, and more often when events indicate the assets may be impaired.

During the first six months of 2010, ShoreMaster's performance was below its 2010 budget and below its performance over the same period in 2009. While updating the second quarter earnings forecast, it became apparent that ShoreMaster's commercial marina and waterfront lines of business continued to be adversely impacted by the economic recession in 2010. The Consumer Confidence Index declined 9.8% in June 2010 around increasing uncertainty and apprehension about the future state of the economy and labor market. The Purchasing Managers' Index also experienced a drop in June around concerns over the status of the economic recovery. These conditions have resulted in a reduction in incoming orders in the commercial marina business. As a result of the poor first half 2010 performance and new economic indicators, ShoreMaster's new forecast projects a slower recovery from the economic recession than was expected in 2009.

In light of the continuing economic uncertainty and delayed economic recovery, ShoreMaster revised its current sales and operating cash flow projections downward and reassessed its fair value to determine if its goodwill and other assets were impaired. ShoreMaster used a discounted cash flow model using a risk adjusted weighted average cost of capital discount rate of 14% to determine its fair value. The fair value determination indicated ShoreMaster's goodwill and intangible assets were 100% impaired and its long-lived assets were partially impaired, resulting in the following impairment charges in June 2010:

(in thousands)		
Goodwill	$	12,259
Brand/Trade Name		4,869
Other Intangible Assets		507

Long-Lived Assets		2,105
Total Asset Impairment Charges	$	19,740

As of December 31, 2009 an assessment of the carrying amounts of our goodwill indicated no impairment and the fair values of our remaining reporting units are in excess of their respective book values.

We currently have $12.0 million of goodwill and $0.7 million in nonamortizable trade names recorded on our balance sheet related to the acquisition of BTD and its subsidiary companies. BTD provides stamped metal parts and fabricated metal products to a number of equipment and product manufacturers and assemblers throughout the United States. We expect BTD to return to 2008 revenue and earnings levels by 2012. If current economic conditions continue to impact sales of manufactured metal products and BTD is not able to achieve sales and earnings consistent with 2008 levels as projected, the reductions in anticipated cash flows from this business may indicate, in a future period, that its fair value is less than its carrying value resulting in an impairment of some or all of the goodwill and nonamortizable intangible assets associated with BTD along with a corresponding charge against earnings.

No events occurred in the first half of 2010 that would change our current conclusions on the impairment of this goodwill. We continue to monitor BTD’s business conditions for any triggering event that would cause us to accelerate our goodwill review from our normal testing timeframes.

An impairment charge consisting of the goodwill and nonamortizable intangible assets of BTD would not have a significant impact on our financial position and would not put us in violation of our debt covenants.

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 similar expressions are intended to identify forward-looking statements within the meaning of the Act and are included, along with this statement, for purposes of complying with the safe harbor provision of the Act.

The following factors, among others, could cause our actual results 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.

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

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

- We rely on access to the 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, our ability to implement our business plans may be adversely affected.

- Disruptions, uncertainty or volatility in the financial markets can also adversely impact our results of operations, the ability of our 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.

- The value of our defined benefit pension plan assets declined significantly in 2008 due to volatile equity markets. Asset values increased in 2009 and we made a $4 million discretionary contribution to the pension plan in 2009. If the market value of pension plan assets declines again as in 2008 or does not increase as projected and relief under the Pension Protection Act is no longer granted, we could be required to contribute additional capital to the pension plan in future years.

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

- A sustained decline in our common stock price below book value or declines in projected operating cash flows at any of our operating companies may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as credit facility covenants.

- Economic conditions could negatively impact our businesses.

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

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

- Our plans to acquire additional businesses and grow and operate our nonelectric businesses could be limited by state law.
- 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.
- Certain of our operating companies sell products to consumers that could be subject to recall.
- Competition is a factor in all of our businesses.
- We may experience fluctuations in revenues and expenses related to our operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to our shareholders or scheduled payments on our debt obligations.
- In September 2009, OTP announced its withdrawal as a participating utility and the lead developer for the planned construction of a second electric generating unit at its Big Stone Plant site. As of June 30, 2010 OTP had $7.7 million in incurred costs related to the project that have not been approved for recovery and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve its rates. If OTP is denied recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed to be unrecoverable.
- Actions by the regulators of the electric segment could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.
- OTP could be required to absorb a disproportionate share of costs for investments in transmission infrastructure required to provide independent power producers access to the transmission grid. These costs may not be recoverable through a transmission tariff and could result in reduced returns on invested capital and/or increased rates to OTP's retail electric customers.
- OTP’s 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.
- Fluctuations in wholesale electric sales and prices could result in earnings volatility.
- 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.
- Changes to regulation of generating plant emissions, including but not limited to carbon dioxide (“CO2”) emissions, could affect our operating costs and the costs of supplying electricity to our customers.
- 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.
- Our plastic pipe companies compete against a large number of other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish the pipe companies’ products from those of its competitors.

- Reductions in PVC resin prices can negatively impact PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.

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

- 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 continue to maintain agreements with Philips Medical from which the businesses derive significant revenues from the sale and service of Philips Medical diagnostic imaging equipment.

- 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 equipment.

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

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

- Our food ingredient processing business could be adversely affected by changes in foreign currency exchange rates.

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At June 30, 2010 we had exposure to market risk associated with interest rates because we had $46.5 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 3.25% under our $200 million revolving credit facility and $21.0 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 0.5% under OTP's $170 million revolving credit facility. At June 30, 2010 we had exposure to changes in foreign currency exchange rates. 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. 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 14.6% of IPH sales in the first half of 2010 were outside the United States and the Canadian operation of IPH pays its operating expenses in Canadian dollars. IPH's Canadian subsidiary has locked in exchange rates for the exchange of U.S. dollars (USD) for Canadian dollars (CAD) for approximately 70% of its cash needs for the period July 1, 2010 through December 31, 2010 by entering into forward foreign currency exchange contracts. On June 30, 2010 IPH's Canadian subsidiary held contracts for the exchange of $3.75 million USD for $3.9 million CAD.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. As of June 30, 2010 we had $10.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on June 30, 2010, 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, sales volume has been higher and when resin prices are falling, sales volumes has been lower. Operating income may 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, lumber, aluminum, cement and resin. The price and availability of these raw materials could affect the revenues and earnings of our manufacturing segment.

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of June 30, 2010 OTP had recognized, on a pretax basis, $1,439,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. 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 OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and NYMEX. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy sales contracts that are marked to market as of June 30, 2010, are 100% offset by forward energy purchase contracts in terms of volumes and delivery periods but not in terms of delivery points. The differential in forward prices at the different delivery locations currently results in a mark-to-market unrealized gain on OTP's open forward 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. There was price risk on open positions as of June 30, 2010 because the open purchases were not at the same delivery points as the open sales.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity on our consolidated balance sheet as of June 30, 2010 and the change in our consolidated balance sheet position from December 31, 2009 to June 30, 2010:

(in thousands)	Year-to-Date June 30, 2010
Fair Value at Beginning of Year	$ 1,030
Less: Amount Realized on Contracts Entered into in 2009 and Settled in 2010	206
Changes in Fair Value of Contracts Entered into in 2009	--
Net Fair Value of Contracts Entered into in 2009 at End of Period	824
Changes in Fair Value of Contracts Entered into in 2010	615
Net Fair Value End of Period	$ 1,439

The $1,439,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on June 30, 2010 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	3rd Quarter 2010	4th Quarter 2010	2011	2012	Total
Net Gain	$ 717	$ 81	$ 320	$ 321	$ 1,439

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of June 30, 2010 was $796,000. As of June 30, 2010 OTP had a net credit risk exposure of $2,000,000 from five counterparties with investment grade credit ratings. OTP had no exposure at June 30, 2010 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

The $2,000,000 credit risk exposure includes net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after June 30, 2010. 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 to increase prices for its finished products to recover increases in fuel costs. In order to limit its exposure to fluctuations in future prices of natural gas, IPH entered into contracts with a fuel supplier in December 2009 for firm purchases of natural gas to cover portions of its anticipated natural gas needs in Ririe, Idaho through August 2010 at fixed prices. These contracts qualify for the normal purchase exception to mark-to-market accounting under Accounting Standards Codification 815-10-15.

IPH's Canadian subsidiary records its sales and carries its receivables in USD but pays its expenses for goods and services consumed in Canada in CAD. 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 USD and the CAD, IPH's Canadian subsidiary entered into forward contracts for the exchange of USD into CAD in May 2010. Each contract was for the exchange of $250,000 USD for the amount of CAD stated in each contract.

The following table lists the contracts outstanding as of June 30, 2010:

(in thousands)	Settlement Periods	USD	CAD
Contracts entered into in May 2010	July 2010 - December 2010	$3,750	$3,901

The following tables show the effect of marking to market IPH's foreign currency exchange forward windows and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of June 30, 2010 and December 31, 2009, and the change in the Company's consolidated balance sheet position from December 31, 2009 to June 30, 2010:

(in thousands)	June 30, 2010
Fair Value of IPH Foreign Currency Exchange Forward Windows included in:	
Other Current Assets	$ --
Other Accrued Current Liabilities	(97)
Net Fair Value of Foreign Currency Exchange Forward Windows	$ (97)

(in thousands)	Year-to-Date June 30, 2010
Fair Value at Beginning of Year	$ --
Changes in Fair Value of Contracts Entered into in 2010	(97)
Net Fair Value End of Period	$ (97)

These 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 do not qualify for hedge accounting treatment because the timing of their settlements did not and will not coincide with the payment of specific bills or existing contractual obligations. The foreign currency exchange forward contracts outstanding as of June 30, 2010 were valued and marked to market on June 30, 2010 based on quoted exchange values on June 30, 2010.

Item 4. Controls and Procedures

Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of June 30, 2010, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of June 30, 2010.

During the fiscal quarter ended June 30, 2010, 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

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 alleged certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act (CAA) and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged 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 CAA and the South Dakota SIP. The Sierra Club alleged 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 sought both declaratory and injunctive relief to bring the defendants into compliance with the CAA 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 was and is being operated in compliance with the CAA and the South Dakota SIP.

The defendants filed a motion to dismiss the Sierra Club complaint on August 12, 2008. On March 31, 2009 and April 6, 2009, the U.S. District Court for the District of South Dakota (Northern Division) issued a Memorandum and Order and Amended Memorandum and Order, respectively, granting the defendants' motion to dismiss the Sierra Club complaint. On April 17, 2009 the Sierra Club filed a motion for reconsideration of the Amended Memorandum Opinion and Order. The Sierra Club motion was opposed by the defendants. The Sierra Club motion for reconsideration was denied on July 22, 2009. On July 30, 2009 the Sierra Club filed a notice of appeal to the 8th U.S. Circuit Court of Appeals. Briefing was complete on January 22, 2010 on filing of the Sierra Club's reply brief. Oral arguments before the Court of Appeals were heard on May 11, 2010. The ultimate outcome of this matter cannot be determined at this time.

Other

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 the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under Part I, Item 1A, "Risk Factors" on pages 29 through 35 of the Company's Annual Report on Form 10-K for the year ended December 31, 2009.

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

The Company does not have a publicly announced stock repurchase program. The following table shows common shares that were surrendered to the Company by employees to pay taxes in connection with shares issued for incentive awards under the Company's 1999 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
April 2010	6,379	$ 21.87
May 2010	--	--
June 2010	--	--
Total	6,379	

Item 6. Exhibits

4.1 Second Amended and Restated Credit Agreement dated as of May 4, 2010, between Otter Tail Corporation and the Banks named therein, U.S. Bank National Association, a national banking association, as administrative agent for the Banks and as Lead Arranger, Bank of America, N.A. and JPMorgan Chase Bank, National Association, as Co-Syndication Agents, and KeyBank National Association, as Documentation Agent (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation on May 10, 2010).

4.2 Amendment No. 3 dated as of June 23, 2010 to Note Purchase Agreement dated as of February 23, 2007, between Otter Tail Corporation and Cascade Investment, L.L.C. (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation on June 29, 2010).

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.

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101.INS XBRL Instance Document.

101.SCH XBRL Taxonomy Extension Schema Document.

101.CAL XBRL Taxonomy Extension Calculation Linkbase Document.

101.LAB XBRL Taxonomy Extension Label Linkbase Document.

101.PRE XBRL Taxonomy Extension Presentation Linkbase Document.

101.DEF XBRL Taxonomy Extension Definition Linkbase Document.

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: August 9, 2010

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