Otter Tail Corp
Form 10-Q
November 08, 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	September 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

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 ___

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 __

Non-accelerated filer __ Smaller reporting company __
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act).
Yes No X

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

October 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)	September 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	$--	$4,432
Accounts Receivable:		
Trade—Net	143,918	95,747
Other	11,709	10,883
Inventories	88,404	86,515
Deferred Income Taxes	11,384	11,457
Accrued Utility and Cost-of-Energy Revenues	12,042	15,840
Costs and Estimated Earnings in Excess of Billings	57,046	61,835
Income Taxes Receivable	19,550	48,049
Other	17,288	15,265
Total Current Assets	361,341	350,023
Investments	9,825	9,889
Other Assets	26,630	26,098
Goodwill	94,306	106,778
Other Intangibles—Net	27,444	33,887
Deferred Debits		
Unamortized Debt Expense	6,846	7,625
Regulatory Assets and Other Deferred Debits	130,686	121,751
Total Deferred Debits	137,532	129,376
Plant		
Electric Plant in Service	1,320,352	1,313,015
Nonelectric Operations	388,628	362,088
Construction Work in Progress	42,904	23,363
Total Gross Plant	1,751,884	1,698,466
Less Accumulated Depreciation and Amortization	648,260	599,839
Net Plant	1,103,624	1,098,627
Total	$1,760,702	$1,754,678

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	September 30, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$93,973	$7,585
Current Maturities of Long-Term Debt	615	59,053
Accounts Payable	88,543	83,724
Accrued Salaries and Wages	21,972	21,057
Accrued Taxes	10,541	11,304
Derivative Liabilities	19,111	14,681
Other Accrued Liabilities	11,419	9,638
Total Current Liabilities	246,174	207,042
Pensions Benefit Liability	78,232	95,039
Other Postretirement Benefits Liability	39,107	37,712
Other Noncurrent Liabilities	23,333	22,697
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	173,678	155,306
Deferred Tax Credits	45,623	47,660
Regulatory Liabilities	65,698	64,274
Other	513	562
Total Deferred Credits	285,512	267,802
Capitalization		
Long-Term Debt, Net of Current Maturities	435,572	436,170
Class B Stock Options of Subsidiary	524	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	250,445	250,398
Retained Earnings	207,261	243,352
Accumulated Other Comprehensive Loss	(620)	(1,315)
Total Common Equity	636,748	671,496
Total Capitalization	1,088,344	1,124,386
Total	$1,760,702	$1,754,678

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
Operating Revenues				
Electric	$88,719	$73,506	$255,966	$232,595
Nonelectric	191,948	183,934	557,082	548,941
Total Operating Revenues	280,667	257,440	813,048	781,536
Operating Expenses				
Production Fuel - Electric	18,210	13,172	55,611	43,585
Purchased Power - Electric System Use	10,254	11,112	32,730	40,362
Electric Operation and Maintenance Expenses	26,959	23,327	84,365	79,216
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	152,455	141,318	434,493	429,598
Other Nonelectric Expenses	35,353	30,476	101,240	93,520
Asset Impairment Charge	--	--	19,740	--
Product Recall and Testing Costs	--	--	--	1,766
Depreciation and Amortization	20,357	18,345	59,991	54,265
Property Taxes - Electric	2,271	2,194	7,222	6,939
Total Operating Expenses	265,859	239,944	795,392	749,251
Operating Income	14,808	17,496	17,656	32,285
Other Income	1,205	1,609	3,129	3,627
Interest Charges	9,294	7,358	27,729	20,280
Income (Loss) Before Income Taxes	6,719	11,747	(6,944)	15,632
Income Tax Expense (Benefit)	618	1,155	(3,544)	(2,079)
Net Income (Loss)	6,101	10,592	(3,400)	17,711
Preferred Dividend Requirement and Other Adjustments	187	184	650	552
Earnings Available for Common Shares	$5,914	$10,408	$(4,050)	$17,159
Average Number of Common Shares Outstanding—Basic	35,806,453	35,528,190	35,775,418	35,413,893
Average Number of Common Shares Outstanding—Diluted	36,076,421	35,788,293	35,775,418	35,670,244
Earnings Per Common Share:				
Basic	$0.17	$0.29	$(0.11)	$0.48
Diluted	$0.16	$0.29	$(0.11)	$0.48
Dividends Per Common Share	$0.2975	$0.2975	$0.8925	$0.8925

See accompanying notes to consolidated financial statements.

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

(in thousands)	Nine Months Ended September 30, 2010	2009
Cash Flows from Operating Activities		
Net Income (Loss)	$(3,400)	$17,711
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	59,991	54,265
Asset Impairment Charge	19,740	--
Deferred Tax Credits	(2,037)	(1,666)
Deferred Income Taxes	17,300	8,243
Change in Deferred Debits and Other Assets	(1,273)	(2,909)
Discretionary Contribution to Pension Plan	(20,000)	(4,000)
Change in Noncurrent Liabilities and Deferred Credits	5,534	7,497
Allowance for Equity Funds Used During Construction	(8)	(2,940)
Change in Derivatives Net of Regulatory Deferral	218	(1,512)
Stock Compensation Expense – Equity Awards	1,973	2,664
Other—Net	(444)	736
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(48,963)	29,993
Change in Inventories	(1,728)	18,721
Change in Other Current Assets	4,551	29,329
Change in Payables and Other Current Liabilities	92	(32,506)
Change in Interest Payable and Income Taxes Receivable/Payable	29,329	16,953
Net Cash Provided by Operating Activities	60,875	140,579
Cash Flows from Investing Activities		
Capital Expenditures	(62,867)	(150,138)
Proceeds from Disposal of Noncurrent Assets	2,709	4,730
Net Increase in Other Investments	(1,669)	(20,805)
Net Cash Used in Investing Activities	(61,827)	(166,213)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	4,784	--
Net Short-Term Borrowings	86,388	(12,414)
Proceeds from Issuance of Common Stock	549	4,637
Proceeds from Issuance of Class B Stock of Subsidiary	158	--
Common Stock Issuance Expenses	(142)	(23)
Payments for Retirement of Common Stock	(401)	(229)
Payments for Retirement of Class B Stock of Subsidiary	(1,017)	--
Proceeds from Issuance of Long-Term Debt	95	75,005
Short-Term and Long-Term Debt Issuance Expenses	(1,699)	(3,693)
Payments for Retirement of Long-Term Debt	(59,166)	(5,983)
Dividends Paid and Other Distributions	(32,824)	(32,239)
Net Cash (Used in) Provided by Financing Activities	(3,275)	25,061
Effect of Foreign Exchange Rate Fluctuations on Cash	(205)	(926)

Net Change in Cash and Cash Equivalents	(4,432)	(1,499)
Cash and Cash Equivalents at Beginning of Period	4,432	7,565
Cash and Cash Equivalents at End of Period	$--	$6,066

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated 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 nine-month periods ended September 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 24.3% for the three months ended September 30, 2010 compared with 27.4% for the three months ended September 30, 2009 and 24.6% for the nine months ended September 30, 2010 compared with 27.5% for the nine months ended September 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)	September 30, 2010	December 31, 2009

Costs Incurred on Uncompleted Contracts	$	436,510	$	400,577
Less Billings to Date		(419,007)		(400,711)
Plus Estimated Earnings Recognized		33,614		59,202
	$	51,117	$	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)	September 30, 2010	December 31, 2009
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 57,046	$ 61,835
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(5,929)	(2,767)
	$ 51,117	$ 59,068

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI), the Company’s wind tower manufacturer, were $47,887,000 as of September 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 $9,961,000 on September 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, but will automatically renew for two consecutive 12-month periods and can continue to renew up to 60 months if neither party terminates the agreement. The minimum notice period for termination is two months. Currently, DMI does not intend to terminate the agreement. Accounts receivable sold totaled $44,100,000 in the first nine months of 2010 compared with $114,500,000 in the first nine months of 2009. Discounts, fees and commissions charged to operating expenses for the three month periods ended September 30, 2010 and 2009 were $45,000 and $37,000, respectively. Discounts, fees and commissions charged to operating expenses for the nine month periods ended September 30, 2010 and 2009 were $152,000 and $304,000, 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 September 30, 2010 and 2009 were $13,000 and $75,000, respectively. Financing assistance costs charged to revenue for the nine month periods ended September 30, 2010 and 2009 were $97,000 and $308,000, respectively.

Supplemental Disclosures of Cash Flow Information

(in thousands)	Nine Months Ended September 30, 2010	2009
Increases in Accounts Payable Related to Capital Expenditures	$ 63	$ 9,535

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 September 30, 2010 and December 31, 2009:

September 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	$ 1,013	$ --	
Forward Energy Contracts		6,306	
Investments of Captive Insurance Company:			
Corporate Debt Securities	8,469		
Total Assets	$ 9,482	$ 6,306	
Liabilities:			
Forward Energy Contracts	$ --	$ 19,095	
Foreign Currency Exchange Forward Windows		16	
Total Liabilities	$ --	$ 19,111	

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

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Inventories
Inventories consist of the following:

(in thousands)	September 30, 2010	December 31, 2009
Finished Goods	$ 42,354	$ 42,784
Work in Process	6,344	3,824
Raw Material, Fuel and Supplies	39,706	39,907
Total Inventories	$ 88,404	$ 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 resulted in a reduction in incoming orders in the commercial marina business. As a result of the poor first half 2010 performance and the economic indicators, ShoreMaster projected 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 sales and operating cash flow projections downward in the second quarter of 2010 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

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

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

(in thousands)	Balance December 31, 2009	Adjustment to Goodwill in 2010	Goodwill Acquired in 2010	Balance September 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 September 30, 2010 and December 31, 2009:

September 30, 2010 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Customer Relationships	$ 26,972	$ 4,636	$ 22,336	15 – 25 years
Covenants Not to Compete	1,704	1,652	52	3 – 5 years
Other Intangible Assets Including Contracts	930	891	39	5 – 30 years
Total	$ 29,606	$ 7,179	$ 22,427	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 5,017	$ --	$ 5,017	
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 $1,083,000 for the nine months ended September 30, 2010 compared with $1,250,000 for the nine months ended September 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 September 30,		Nine Months Ended September 30,	
(in thousands)	2010	2009	2010	2009
Net Income (Loss)	$ 6,101	$ 10,592	$ (3,400)	$ 17,711
Other Comprehensive Income (net-of-tax):				
Foreign Currency Translation Gain	484	1,119	295	1,703
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	105	88	314	192
Unrealized Gain on Available-for-Sale Securities	54	53	86	79
Total Other Comprehensive Income	643	1,260	695	1,974
Total Comprehensive Income (Loss)	$ 6,744	$ 11,852	$ (2,705)	$ 19,685

Reclassifications

In order to provide a consistent representation of regulatory assets on the face of the Company's consolidated balance sheets and in the notes to its consolidated financial statements, deferred amounts related to premiums paid on the reacquisition of debt related to regulated operations as of December 31, 2009 totaling $3,051,000 were reclassified from Unamortized Debt Expense and Reacquisition Premiums to Regulatory Assets and Other Deferred Debits in September 2010, and the line item title on the face of the Company's consolidated balance sheet was changed from Unamortized Debt Expense and Reacquisition Premiums to Unamortized Debt Expense. The deferral of gains and losses incurred on the reacquisition of debt is an accounting treatment prescribed for regulated utilities under regulatory accounting rules and, as such, deferred losses on the reacquisition of debt are generally classified as regulatory assets. The Company has historically reported the unamortized balance of losses on the reacquisition of debt related to its regulated electric utility operations as a regulatory asset in the notes to its consolidated financial statements.

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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
United States of America	97.7 %	97.7 %	97.3 %	97.9 %
Canada	1.1 %	0.7 %	1.7 %	0.9 %
All Other Countries (none greater than 1%)	1.2 %	1.6 %	1.0 %	1.2 %

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

Operating Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2010	2009	2010	2009
Electric	$ 88,762	$ 73,553	$ 256,132	$ 232,757
Plastics	26,736	27,353	76,562	63,066
Manufacturing	72,414	75,928	235,403	248,790
Health Services	24,300	27,053	73,116	83,412
Food Ingredient Processing	19,478	18,691	56,648	59,358
Other Business Operations	50,301	36,123	118,776	97,615
Corporate Revenues and Intersegment Eliminations	(1,324)	(1,261)	(3,589)	(3,462)
Total	$ 280,667	$ 257,440	$ 813,048	$ 781,536

Interest Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2010	2009	2010	2009
Electric	$ 5,146	$ 5,380	$ 15,728	$ 13,657
Plastics	403	181	1,194	580

Manufacturing	2,803	1,346	7,988	4,064
Health Services	377	108	902	304
Food Ingredient Processing	35	9	100	29
Other Business Operations	353	118	889	350
Corporate and Intersegment Eliminations	177	216	928	1,296
Total	$ 9,294	$ 7,358	$ 27,729	$ 20,280

Income Tax Expense (Benefit)

(in thousands)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Electric	$ 4,323	$ 1,419	$ 8,769	$ 2,358
Plastics	238	896	873	(553)
Manufacturing	(4,266)	236	(10,147)	(776)
Health Services	311	(395)	(66)	(471)
Food Ingredient Processing	1,193	1,068	3,030	3,406
Other Business Operations	789	(141)	(734)	(1,291)
Corporate	(1,970)	(1,928)	(5,269)	(4,752)
Total	$ 618	$ 1,155	$ (3,544)	$ (2,079)

Earnings Available for Common Shares

(in thousands)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Electric	$ 12,375	$ 9,527	$ 24,527	$ 22,080
Plastics	367	1,298	1,380	(869)
Manufacturing	(8,078)	100	(26,413)	(1,157)
Health Services	421	(649)	(235)	(875)
Food Ingredient Processing	1,991	1,772	5,277	5,544
Other Business Operations	1,159	(205)	(1,175)	(1,986)
Corporate	(2,321)	(1,435)	(7,411)	(5,578)
Total	$ 5,914	$ 10,408	$ (4,050)	$ 17,159

Total Assets

(in thousands)	September 30, 2010	December 31, 2009
Electric	$ 1,095,169	$ 1,119,822
Plastics	76,289	70,380
Manufacturing	299,959	306,011
Health Services	69,804	58,164
Food Ingredient Processing	91,108	88,478
Other Business Operations	80,375	59,915
Corporate	47,998	51,908
Total	$ 1,760,702	$ 1,754,678

Fourth Quarter 2010 Segment Realignment

Effective October 1, 2010, the Company realigned its business structure and defined its operating segments to be consistent with its business strategy and based on the reporting and review process used by the Company's chief decision makers. The Company's revised reporting segments, which will be reported in the Company's 2010 Annual Report, are as follows:

Corporate will continue to be reported separately along with the Company's reportable business segments in order to reconcile the Company's reportable business segments with its consolidated assets, net income and cash flows.

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.

Renewable Energy Standards, Conservation, Renewable Resource Riders—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 standard. 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 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 OTP's 32 wind turbines at the Ashtabula Wind Energy Center, which 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.

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 MPUC approved OTP's petition for a 2010 MNRRA in the third quarter of 2010 with implementation effective September 1, 2010. This approval increased the MNRRA to $0.00684 per kwh plus $0.298 per kW for the large general service class and $0.00760 per kwh for all other customer classes. The 2010 MNRRA was established with an expected recovery of $16.2 million over the period September 1, 2010 to August 31, 2011. The 2010 MNRRA will be in effect until the MPUC sets another updated MNRRA. The MPUC is also considering in OTP's general rate case whether to move recovery of these renewable projects into OTP's base rates. OTP has recognized a regulatory asset of $7.7 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of September 30, 2010.

Transmission Cost Recovery (TCR) Rider—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 TCR 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 TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010. Beginning February 1, 2010, OTP's TCR 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 September 30, 2010 OTP had accrued a $36,000 liability for transmission related revenues that are subject to refund through the rider. 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 TCR rider rate. The transmission investments will continue to be recovered through OTP's Minnesota TCR rider rate until the MPUC makes a decision on OTP's general rate case. OTP filed a request for an update to its Minnesota TCR rider rate on October 5, 2010.

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. Approval for implementation of an updated NDRRA was received in the third quarter of 2010 with implementation effective September 1, 2010. This approval increased the NDRRA to $0.00473 per kwh plus $0.212 per kW for the large general service class and $0.00551 per kwh for all other customer classes. The 2010 NDRRA was established with an expected recovery of $15.8 million over the period September 1, 2010 to March 31, 2012. The 2010 NDRRA will be in effect until the NDPSC sets another updated 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 September 30, 2010 consolidated balance sheet includes a regulatory asset of $2.5 million for revenues that are eligible for recovery through the NDRRA but have not been billed to North Dakota customers.

Transmission Cost Recovery Rider—North Dakota law 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. OTP expects to submit a request for an initial North Dakota TCR rider to the NDPSC in the fourth quarter of 2010.

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. 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 South Dakota Public Utilities Commission (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.

2010 General Rate Case Filing— On August 20, 2010 OTP filed a general rate case with the SDPUC requesting an overall revenue increase of approximately $2.8 million, or just under 10.0%, which includes, among other things, recovery of investments and expenses related to renewable resources. On September 28, 2010 the SDPUC suspended OTP’s proposed rates for a period of 180 days to allow time to review OTP’s proposal. The SDPUC ordered the assessment of a filing fee up to $125,000 to cover a portion of its expenses to review the filing.

Transmission Cost Recovery Rider—South Dakota law 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 expects to submit a request for an initial South Dakota TCR rider to the SDPUC in the fourth quarter of 2010.

Federal

Revenue Sufficiency Guarantee (RSG) Charges—Since 2006, OTP has been a party to litigation before the Federal Energy Regulatory Commission (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, 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 FERC issued three orders on RSG on August 30, 2010. None of the orders is expected to have a material impact on OTP.

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. The appeal was rejected in June 2010.

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. Required permits from the Minnesota Department of Transportation, Minnesota Department of Natural Resources and the U.S. Army Corps of Engineers are expected to be received by the end of 2010. A Transmission Capacity Exchange Agreement, allocating transmission capacity rights to owners across the Monticello to St. Cloud portion of the project, was accepted by the FERC in the third quarter of 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 second quarter of 2011. Minnesota State Environmental Impact Statement (EIS) scoping meetings were held in September 2010, with public hearings scheduled for November 2010. On October 8, 2010, OTP submitted its application for a Certificate of Public Convenience and Necessity from the NDPSC for the North Dakota portion of the Fargo–Monticello 345 kV project.

The route permit application for the Brookings project was filed in the fourth quarter of 2008. On July 15, 2010 the MPUC voted to approve most of the Brookings route permit application. On September 15, 2010 the MPUC approved a route permit for five of six project line segments, with the exception of the line 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 Service related to this section of the proposed route. A route permit for the final segment is expected in the first quarter of 2011. An application for a South Dakota route permit is under development and is expected to be filed with the SDPUC in the fourth quarter of 2010.

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. The MPUC approved the CON for this project on July 9, 2009. A route permit application was filed with the MPUC in the second quarter of 2008 for the Bemidji-Grand Rapids project. On October 28, 2010 the MPUC approved the route permit application for the project. A written order on the route permit application is expected in November 2010. The joint state and federal EIS was published by the federal agencies on September 7, 2010, and the project's Transmission Capacity Exchange Agreement was accepted and approved by the FERC in the third quarter of 2010.

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 2010. On October 6, 2010 the NDPSC adopted an order approving a settlement between OTP and intervener NDPSC advocacy staff, and issuing an advance determination of prudence to OTP for participation in the three Group 1 projects. The order is subject to a number of terms and conditions in addition to the settlement agreement, including the provision of additional information on the eventual resolution of cost allocation issues relevant to the Brookings-Southeast Twin Cities project and its associated impact on North Dakota.

Big Stone Air Quality Control System

Big Stone Plant has been deemed to potentially reduce visibility in Class I areas in Minnesota, North Dakota, South Dakota and Michigan. The federal Environmental Protection Agency (EPA) has required South Dakota to submit an implementation plan describing how affected generation sources will reduce emissions in compliance with Best Available Retrofit Technology (BART) guidelines. Under the South Dakota Implementation Plan approved on September 15, 2010, Big Stone Plant must install and operate a new BART compliant air quality control system to reduce emissions within five years of the EPA's approval of the implementation plan. OTP intends to file a petition in the fourth quarter of 2010 asking the MNPUC for advance determination of prudence for the costs of the BART compliant air quality control system at Big Stone Plant attributable to serving OTP's Minnesota customers.

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 North Dakota portion of Big Stone II generation costs is being recovered over a 36 month period 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 September 30, 2010 OTP had $8.0 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 11, 2010. OTP requested recovery of the South Dakota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in South Dakota on August 20, 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)	September 30, 2010	December 31, 2009
Regulatory Assets - Current:		
Accrued Cost-of-Energy Revenue	$826	$1,175
Regulatory Assets – Long-Term:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$76,234	$78,871
Deferred Marked-to-Market Losses	13,778	7,614
Unrecovered Project Costs – Big Stone II	11,746	12,982
Minnesota Renewable Resource Rider Accrued Revenues	7,674	5,324
Deferred Income Taxes	5,902	5,441
Deferred Conservation Improvement Program Costs	4,007	1,908
Debt Reacquisition Premiums	3,417	3,051
North Dakota Renewable Resource Rider Accrued Revenues	2,531	566
Accumulated ARO Accretion/Depreciation Adjustment	2,113	1,808
General Rate Case Recoverable Expenses	1,815	1,693
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	810	1,091
South Dakota – Asset-Based Margin Sharing Shortfall	406	330
Deferred Holding Company Formation Costs	207	248
MISO Schedule 16 and 17 Deferred Administrative Costs - MN	46	252
Minnesota Transmission Rider Accrued Revenues	--	420
Plant Acquisition Costs	--	18
Total Regulatory Assets – Long Term	$130,686	$121,617
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$60,837	$58,937
Deferred Income Taxes	4,459	4,965
Deferred Marked-to-Market Gains	160	224
Deferred Gain on Sale of Utility Property – Minnesota Portion	130	134
South Dakota – Asset-Based Margin Sharing Excess	76	14
Minnesota Transmission Refund Payable	36	--
Total Regulatory Liabilities	$65,698	$64,274
Net Regulatory Asset Position	$65,814	$58,518

The Accrued Cost-of-Energy Revenue will be collected from retail electric customers over the next nine months.

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 September 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-MW 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. In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers over 36 months beginning in August 2010. The unrecovered balance of the North Dakota portion of costs as of September 30, 2010, of $3,750,000 will be recovered over the next 34 months. OTP has requested recovery of the Minnesota and South Dakota portions of Big Stone II development costs as part of its current general rate cases being conducted in those states and has deferred recognition of these costs as operating expenses pending determination of recoverability by the MNPUC and the SDPUC.

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 September 30, 2010. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over the next 42 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.

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

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 22 years.

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 September 30, 2010. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over the next 39 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 43 months.

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

South Dakota – Asset-Based Margin Sharing Shortfall or Excess 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.

Deferred Holding Company Formation Costs will be amortized over the next 45 months.

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

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

The Deferred Gain on Sale of Utility Property will be paid to Minnesota retail electric customers over the next 24 years.

Minnesota Transmission Rider Refund Payable is expected to be refunded to Minnesota retail electric customers over the next 18 months.

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 September 30, 2010 OTP had recognized, on a pretax basis, $829,000 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 September 30, 2010 and December 31, 2009, and the change in the Company's consolidated balance sheet position from December 31, 2009 to September 30, 2010:

(in thousands)	September 30, 2010	December 31, 2009
Current Asset – Marked-to-Market Gain	$ 6,306	$ 8,321
Regulatory Asset – Deferred Marked-to-Market Loss	13,778	7,614
Total Assets	20,084	15,935
Current Liability – Marked-to-Market Loss	(19,095)	(14,681)
Regulatory Liability – Deferred Marked-to-Market Gain	(160)	(224)
Total Liabilities	(19,255)	(14,905)
Net Fair Value of Marked-to-Market Energy Contracts	$ 829	$ 1,030

(in thousands)	Year-to-Date September 30, 2010
Fair Value at Beginning of Year	$ 1,030
Less: Amount Realized on Contracts Entered into in 2009 and Settled in 2010	308
Changes in Fair Value of Contracts Entered into in 2009	--
Net Fair Value of Contracts Entered into in 2009 at End of Period	722
Changes in Fair Value of Contracts Entered into in 2010	107
Net Fair Value End of Period	$ 829

The $829,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on September 30, 2010 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	4th Quarter 2010	2011	2012	Total
Net Gain	$ 200	$ 308	$ 321	$ 829

Realized and unrealized net gains on forward energy contracts of $144,000 for the three months ended September 30, 2010, $1,945,000 for the nine months ended September 30, 2010, $956,000 for the three months ended September 30, 2009 and $2,130,000 for the nine months ended September 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 September 30, 2010 was $277,000. As of September 30, 2010 OTP had a net credit risk exposure of $815,000 from eleven counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. OTP had no exposure at September 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 $815,000 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 September 30, 2010. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $336,000 on certain of OTP's derivative energy contracts included in the $19,095,000 derivative liability on September 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 September 30, 2010 was $11,520,000, for which OTP had posted $5,793,000 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 September 30, 2010, OTP would have been required to post $5,727,000 in additional collateral to its counterparties. The remaining derivative liability balance of $7,239,000 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 September 2010 for firm purchases of natural gas to cover a portion of its anticipated natural gas needs in Ririe, Idaho from October 2010 through September 2011 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 September 30, 2010:

(in thousands)	Settlement Periods	USD	CAD
Contracts entered into in May 2010	October 2010 - December 2010	$ 1,500	$ 1,563

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 sheet as of September 30, 2010, and the change in the Company's consolidated balance sheet position from December 31, 2009 to September 30, 2010:

(in thousands)	September 30, 2010
Fair Value of IPH Foreign Currency Exchange Forward Windows included in:	
Other Current Assets	$ --
Other Accrued Current Liabilities	(16)
Net Fair Value of Foreign Currency Exchange Forward Windows	$ (16)

(in thousands)	Year-to-Date September 30, 2010
Fair Value at Beginning of Year	$ --
Changes in Fair Value of Contracts Entered into in 2010	(16)
Net Fair Value End of Period	$ (16)

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 come 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 September 30, 2010 were valued and marked to market on September 30, 2010 based on quoted exchange values on September 30, 2010. Realized and unrealized net (losses) gains on IPH's foreign currency exchange forward windows of $64,000 for the three month period ended September 30, 2010, and $(41,000) for the nine month period ended September 30, 2010, $90,000 for the three months ended September 30, 2009 and $180,000 for the nine months ended September 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 September 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, September 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 nine-month periods ended September 30, 2010 and 2009:

Three Months Ended September 30,	Options Outstanding	Range of Exercise Prices
2010	383,460	\$24.93 – \$31.34
2009	415,710	\$24.93 – \$31.34

Nine Months Ended September 30,	Options Outstanding	Range of Exercise Prices
2010	383,460	\$24.93 – \$31.34
2009	415,710	\$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 six months ended September 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 September 30, 2010 the remaining unrecognized compensation expense related to stock-based compensation was approximately $5.6 million (before income taxes) which will be amortized over a weighted-average period of 2.1 years.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2010	2009	2010	2009
Employee Stock Purchase Plan (15% discount)	$ 64	$ 76	$ 205	$ 238
Restricted Stock Granted to Directors	148	141	446	395
Restricted Stock Granted to Employees	239	118	519	320
Restricted Stock Units Granted to Employees	(20)	141	137	410
Stock Performance Awards Granted to Executive Officers	722	712	879	1,934
Totals	$ 1,153	$ 1,188	$ 2,186	$ 3,297

9. Commitments and Contingencies

Electric Utility Construction Contracts and Project Commitments
In the third quarter of 2010, the Company's Board of Directors approved OTP's $12.6 million commitment to the Monticello–St. Cloud portion of the Fargo–Monticello 345 kV CapX2020 project. The Monticello–St. Cloud portion of the project began construction in fall 2010 and is expected to be completed by spring 2012.

IPH Potato Supply and Fuel Purchase Commitments
IPH has commitments of approximately $13.8 million for the purchase of a portion of its raw potato supply requirements from October 2010 through September 2011. IPH entered into contracts with a fuel supplier in September 2010 for firm purchases of natural gas to cover a portion of its anticipated natural gas needs in Ririe, Idaho from October 2010 through September 2011 totaling approximately $–0.6 million.

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. On August 12, 2010 the Court of Appeals affirmed the District Court's decision dismissing the Sierra Club complaint. The Sierra Club did not file a petition for rehearing with the Court of Appeals. The deadline for a petition for writ of certiorari with the U.S. Supreme Court is November 10, 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 September 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 September 30, 2010 and December 31, 2009:

(in thousands)	Line Limit	In Use on September 30, 2010	Restricted due to Outstanding Letters of Credit	Available on September 30, 2010	Available on December 31, 2009
Otter Tail Corporation Credit Agreement	$ 200,000	$ 61,000	$ 2,024	$ 136,976	$ 179,755
OTP Credit Agreement	170,000	32,854	250	136,896	167,735
Total	$ 370,000	$ 93,854	$ 2,274	$ 273,872	$ 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 September 30, 2010:

(in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Lines of Credit and Other Short-Term Debt	$ 32,854	$ 119	$ 61,000	$ 93,973
Senior Unsecured Notes 6.63%, due December 1, 2011	90,000			90,000
Pollution Control Refunding Revenue Bonds, Variable, 2.5% at September 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	5,100			5,100
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	20,215			20,215
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
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 September 30, 2010		5,844		5,844
Total	$ 280,715	$ 5,844	$ 150,000	$ 436,559
Less:				
Current Maturities	--	615	--	615
Unamortized Debt Discount	--	366	6	372
Total Long-Term Debt	$ 280,715	$ 4,863	$ 149,994	$ 435,572
Total Short-Term and Long-Term Debt (with current maturities)	$ 313,569	$ 5,597	$ 210,994	$ 530,160

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 the nine month period ended September 30, 2010. In June 2010, IPH exercised its right to repurchase the 400 outstanding IPH Class B common shares for $994,000 in cash and the shares were retired.

In July 2010, IPH bought back nine options to purchase IPH Class B common shares from a former employee for $18,000, the fair value of the options. The book value of the options totaled $14,000. The $2,000 net-of-tax difference between the fair value and book value of the options was charged to retained earnings, and earnings available for common shares were reduced by $2,000 for both the three and nine month periods ended September 30, 2010.

As of September 30, 2010 there were 363 options for the purchase of IPH Class B common shares outstanding with a combined exercise price of $233,000. All 363 outstanding options were “in-the-money” on September 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 September 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 September 30,		Nine Months Ended September 30,	
(in thousands)	2010	2009	2010	2009
Service Cost—Benefit Earned During the Period	$ 997	$ 869	$ 3,491	$ 3,135
Interest Cost on Projected Benefit Obligation	2,990	3,008	9,050	8,958
Expected Return on Assets	(3,483)	(3,439)	(10,283)	(10,335)
Amortization of Prior-Service Cost	172	181	512	543
Amortization of Net Actuarial Loss	511	48	1,501	58
Net Periodic Pension Cost	$ 1,187	$ 667	$ 4,271	$ 2,359

A $20.0 million discretionary contribution was made to the pension plan in September 2010. OTP borrowed $20.0 million on its credit facility in September 2010 to make the discretionary contribution to the pension fund. This contribution increased the Company’s 2009 taxable loss. Tax provisions allow that loss to be carried back against previous years’ income taxes, which will result in an additional tax refund in 2010 of approximately $8.0 million. The timing and level of the contribution to the pension fund will also result in a decrease in future pension benefit costs relative to the costs that would have been incurred had the contribution been delayed until a minimum payment was required.

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 September 30,		Nine Months Ended September 30,	
(in thousands)	2010	2009	2010	2009
Service Cost—Benefit Earned During the Period	$ 165	$ 188	$ 495	$ 564
Interest Cost on Projected Benefit Obligation	417	423	1,253	1,271
Amortization of Prior-Service Cost	19	17	55	53
Amortization of Net Actuarial Loss	120	97	358	289
Net Periodic Pension Cost	$ 721	$ 725	$ 2,161	$ 2,177

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 September 30,		Nine Months Ended September 30,	
(in thousands)	2010	2009	2010	2009
Service Cost—Benefit Earned During the Period	$ 375	$ 301	$ 1,225	$ 903
Interest Cost on Projected Benefit Obligation	855	753	2,405	2,259
Amortization of Transition Obligation	187	187	561	561
Amortization of Prior-Service Cost	58	53	158	159

Amortization of Net Actuarial Loss	248	1	624	3
Effect of Medicare Part D Expected Subsidy	(558)	(297)	(1,558)	(891)
Net Periodic Postretirement Benefit Cost	$ 1,165	$ 998	$ 3,415	$ 2,994

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.

	September 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	(435,572)	(482,778)	(436,170)	(457,907)

15. Income Taxes

The Company's effective income tax rates for the three months ended September 30, 2010 and 2009 were approximately 9.2% and 9.8%, respectively. The Company recorded federal production tax credits (PTCs) and North Dakota wind energy credits totaling approximately $1.8 million in the third of quarter of 2010. In the third quarter of 2009, the Company recorded PTCs and North Dakota wind energy credits totaling approximately $1.6 million.

The Company's effective income tax rates for the nine months ended September 30, 2010 and 2009 were approximately 51.0% and (13.3%), 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 $5.6 million in the first nine 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 nine months of 2009, the Company recorded PTCs and North Dakota wind energy credits totaling $5.5 million on $15.6 million of income before income taxes, which contributed to the negative tax rate for the nine months ended September 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. In September 2010, a $20.0 million discretionary contribution was made to the Company’s pension plan. The contribution increased the Company’s 2009 taxable loss. Tax provisions allow that loss to be carried back against previous years’ income taxes, which will result in an additional tax refund in 2010 of approximately $8.0 million. The Company had not yet received this additional refund as of the date of this report on Form 10-Q.

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

RESULTS OF OPERATIONS

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

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

Consolidated operating revenues were $280.7 million for the three months ended September 30, 2010 compared with $257.4 million for the three months ended September 30, 2009. Operating income was $14.8 million for the three months ended September 30, 2010 compared with $17.5 million for the three months ended September 30, 2009. The Company recorded diluted earnings per share of $0.16 for the three months ended September 30, 2010 compared with $0.29 for the three months ended September 30, 2009.

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 September 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 September 30, 2010	Three Months Ended September 30, 2009
Operating Revenues:		
Electric	$ 43	$ 47
Nonelectric	1,281	1,214
Cost of Goods Sold	1,200	1,202
Other Nonelectric Expenses	124	59

Electric

(in thousands)	Three Months Ended September 30, 2010	2009	Change	% Change
Retail Sales Revenues	$ 77,229	$ 66,067	$ 11,162	16.9
Wholesale Revenues – Company Generation	7,313	3,154	4,159	131.9
Net Revenue – Energy Trading Activity	239	1,190	(951)	(79.9)
Other Revenues	3,981	3,142	839	26.7
Total Operating Revenues	$ 88,762	$ 73,553	$ 15,209	20.7
Production Fuel	18,210	13,172	5,038	38.2
Purchased Power – System Use	10,254	11,112	(858)	(7.7)
Other Operation and Maintenance Expenses	26,959	23,327	3,632	15.6
Depreciation and Amortization	10,036	9,015	1,021	11.3
Property Taxes	2,271	2,194	77	3.5
Operating Income	$ 21,032	$ 14,733	$ 6,299	42.8

The increase in retail sales revenues mainly is due to the following: (1) a $7.2 million increase in revenues mostly due to an 8.4% increase in retail kilowatt-hour (kwh) sales as a result of a 114% increase in cooling degree days between the quarters, as well as rate design changes implemented pursuant to recent rate case decisions, (2) a $1.6 million increase in resource recovery and transmission rider revenues, (3) a $1.3 million increase from interim rates implemented in Minnesota in June 2010, (4) a $0.5 million increase in Minnesota Conservation Investment Program (CIP) surcharge revenues, and (5) a $0.4 million increase in Fuel Clause Adjustment revenues related to an increase in fuel and purchased power costs incurred to serve retail customers.

Wholesale electric revenues from company-owned generation increased as a result of a 93.4% increase in wholesale kwh sales due, in part, to greater plant availability and dispatch. Generating plant output was 31.0% higher in the third quarter of 2010 than in the same period a year ago. 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 increase in other electric operating revenues is mainly due to an increase in transmission services revenue.

The increase in fuel costs is due to a 30.3% increase in kwhs generated from Otter Tail Power Company's (OTP's) steam-powered and combustion turbine generators combined with a 6.1% increase in the cost of fuel per kwh generated. Purchased power costs decreased as a result of a 31.8% decrease in kwhs purchased for retail sales, partially offset by a 35.3% increase in the cost per kwh purchased. Both the increase in kwhs generated and the decrease in kwhs purchased were due to increased plant availability and dispatch in the third quarter of 2010. The increase in other operation and maintenance expenses is mostly due to increases in wage and benefit costs, Minnesota CIP costs and other operating and maintenance expenses. 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 September 30, 2010	2009	Change	% Change
Operating Revenues	$ 26,736	$ 27,353	$ (617)	(2.3)
Cost of Goods Sold	23,278	23,066	212	0.9
Operating Expenses	1,606	1,248	358	28.7
Depreciation and Amortization	858	667	191	28.6
Operating Income	$ 994	$ 2,372	$ (1,378)	(58.1)

Operating revenues for the plastics segment decreased as result of a 13.3% decrease in pounds of polyvinyl chloride (PVC) pipe sold, partially offset by a 12.8% increase in the price per pound of PVC pipe sold related to a 22.4% increase in PVC resin costs between the quarters. The decrease in pounds of PVC pipe sold reflects higher than normal sales volumes in the third quarter of 2009 due to sales opportunities that materialized when a competitor stopped filling customer orders. The cost per pound of PVC pipe sold increased 16.4% between the quarters. Expenses incurred in the third quarter of 2010 in connection with the planned relocation of production equipment from Hampton, Iowa to the plant in Fargo, North Dakota contributed to the increase in operating expenses. Asset additions in 2009 and the acceleration of amortization of leasehold improvements at the Hampton facility contributed to the increase in depreciation expense.

Manufacturing

(in thousands)	Three Months Ended September 30, 2010	2009	Change	% Change
Operating Revenues	$ 72,414	$ 75,928	$ (3,514)	(4.6)
Cost of Goods Sold	67,076	60,339	6,737	11.2
Other Operating Expenses	9,025	8,071	954	11.8
Depreciation and Amortization	5,794	5,778	16	0.3
Operating (Loss) Income	$ (9,481)	$ 1,740	$ (11,221)	--

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

Revenues at DMI Industries, Inc. (DMI) decreased $10.0 million as lower production levels were realized due to a different customer mix and lower productivity while supporting the deliveries to a customer contract.

Revenues at ShoreMaster, Inc. (ShoreMaster) decreased $3.5 million due to a $4.5 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 $1.0 million increase in sales of residential products.

Revenues at BTD Manufacturing, Inc. (BTD) increased $9.2 million due to improved customer demand, better productivity and higher scrap-metal prices.

Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $0.8 million due to increased sales of horticultural and custom products.

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

Cost of goods sold at DMI increased $3.1 million, mainly as a result of incurring $5.6 million in additional costs to complete towers to a customer's new design specifications and to support the customer's delivery schedule for completed towers, partially offset by a reduction in direct costs of tower production related to a decrease in volume of towers produced.

Cost of goods sold at ShoreMaster decreased $2.8 million due to the decrease in sales of commercial products.

Cost of goods sold at BTD increased $6.3 million as a result of a $6.9 million increase in labor, material and overhead costs related to higher sales volumes, mitigated by a $0.6 million reduction in costs due to productivity improvements.

Cost of goods sold at T.O. Plastics increased $0.1 million as a result of a $0.4 million increase in labor and material costs related to higher sales volumes, mitigated by a $0.3 million reduction in costs due to productivity improvements.

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

Other operating expenses at ShoreMaster increased $0.7 million, reflecting a $0.3 million increase in expense related to an increase in allowance for doubtful commercial accounts, a $0.2 million increase in legal costs related to patent protection and a $0.2 million increase in various other operating expenses.

Other operating expenses at BTD increased $0.2 million, mainly due to an increase in labor costs.

Other operating expenses at T.O. Plastics increased $0.1 million mainly due to increases in salary and benefit expenses.

Health Services

	Three Months Ended September 30,			%
(in thousands)	2010	2009	Change	Change
Operating Revenues	$ 24,300	$ 27,053	$ (2,753)	(10.2)
Cost of Goods Sold	17,186	22,260	(5,074)	(22.8)
Operating Expenses	4,353	4,841	(488)	(10.1)
Depreciation and Amortization	1,694	972	722	74.3
Operating Income (Loss)	$ 1,067	$ (1,020)	$ 2,087	204.6

Revenues from scanning and other related services decreased $2.9 million as a result of a 20.5% decrease in scans performed, partially offset by an 8.2% increase in revenue per scan. Revenues from equipment sales and servicing increased $0.1 million. The decrease in costs of goods sold reflects a $1.3 million reduction in material, labor and other direct and indirect costs of sales and a reduction in equipment rental costs of $3.8 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. Through this process, the imaging business has reduced the combined number of units of imaging equipment it leases and owns by 16.4% over the past twelve months. The decrease in operating expenses is mostly related to reductions in salaries, marketing travel and rent expenses. The increase in depreciation expense reflects an increase in owned equipment compared with the same quarter a year ago.

Food Ingredient Processing

(in thousands)	Three Months Ended September 30, 2010	2009	Change	% Change
Operating Revenues	$ 19,478	$ 18,691	$ 787	4.2
Cost of Goods Sold	14,052	13,432	620	4.6
Operating Expenses	1,019	993	26	2.6
Depreciation and Amortization	1,168	1,205	(37)	(3.1)
Operating Income	$ 3,239	$ 3,061	$ 178	5.8

The increase in food ingredient processing revenues is due to a 6.3% increase in pounds of product sold as a result of increased customer demand, slightly offset by a 1.9% decrease in the price per pound of product sold. Cost of goods sold increased as a result of the increase in pounds of product sold, partially offset by a 1.6% decrease in the cost per pound of product sold mainly due to a decrease in raw potato costs.

Other Business Operations

(in thousands)	Three Months Ended September 30, 2010	2009	Change	% Change
Operating Revenues	$ 50,301	$ 36,123	$ 14,178	39.2
Cost of Goods Sold	32,063	23,423	8,640	36.9
Operating Expenses	15,255	12,307	2,948	24.0
Depreciation and Amortization	688	616	72	11.7
Operating Income (Loss)	$ 2,295	$ (223)	$ 2,518	--

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

Revenues at Foley Company increased $9.9 million due to an increase in construction activity.

Revenues at E.W. Wylie Corporation (Wylie) increased $4.0 million as a result of a 9.8% increase in miles driven by company-owned and owner-operated trucks combined with a 13.3% increase in revenue per mile driven and a $2.0 million increase in revenue from brokerage activity. The increase in miles driven reflects increased demand for flatbed services for transporting steel, agricultural equipment and mineral extraction equipment. The increase in revenues per mile driven reflects higher freight rates and price increases for fuel cost recovery related to an 18.0% increase in the average cost per gallon of fuel consumed.

Revenues at Aevenia, Inc. (Aevenia) increased $0.2 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 $8.8 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 overhead costs.

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

Operating expenses at Wylie increased $2.4 million as a result of increases of $1.5 million in contractor and brokerage settlements, $0.6 million in fuel costs and $0.1 million in labor and travel costs. These expense increases were due to the 9.8% increase in miles driven by company-owned and owner-operated trucks combined with an 18.0% increase in the average cost per gallon of fuel consumed and a 39.7% increase in brokerage miles.

Operating expenses at Foley Company increased $0.3 million mainly due to increase in salaries and benefit costs.

Operating expenses at Aevenia increased $0.3 million mainly due to higher employee 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.

	Three Months Ended September 30,			%
(in thousands)	2010	2009	Change	Change
Operating Expenses	$ 4,219	$ 3,075	$ 1,144	37.2
Depreciation and Amortization	119	92	27	29.3

The increase in corporate operating expenses is mainly due to severance costs related to personnel changes in the third quarter of 2010.

Other Income

Other income decreased $0.4 million in the third quarter of 2010 compared with the third quarter of 2009 as a result of a $1.9 million decrease in allowance for equity funds used during construction at OTP as a result of not having a major project under construction in 2010 similar to the Luverne Wind Farm project in 2009, offset by $0.6 million in Minnesota CIP accrued incentives in the third quarter of 2010, an investment loss of $0.5 million in the third quarter of 2009 and $0.2 million decrease in foreign currency transaction losses at IPH.

Interest Charges

Interest charges increased $1.9 million in the third quarter of 2010 compared with the third quarter of 2009 as a result of a $23.6 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 and a $0.4 million reduction in capitalized interest related to a reduction in construction work in progress at OTP. The December 2009 debt offering of $100 million 9.000% Notes due 2016 contributed $2.2 million to the increase in interest expenses, and the retirement of the remaining $58 million of the $75 million Luverne Term Note in January 2010 reduced interest expenses by $0.7 million between the quarters.

Income Taxes

Our effective income tax rates for the three months ended September 30, 2010 and 2009 were approximately 9.2% and 9.8%, respectively. We recorded federal production tax credits (PTCs) and North Dakota wind energy credits totaling $1.8 million in the third of quarter of 2010 compared with $1.6 million in the third quarter of 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.

Comparison of the Nine Months Ended September 30, 2010 and 2009

Consolidated operating revenues were $813.0 million for the nine months ended September 30, 2010 compared with $781.5 million for the nine months ended September 30, 2009. Operating income was $17.7 million for the nine months ended September 30, 2010 compared with $32.3 million for the nine months ended September 30, 2009. The Company recorded diluted earnings per share of ($0.11) for the nine months ended September 30, 2010 compared to $0.48 for the nine months ended September 30, 2009.

Asset Impairment Charge—In light of continuing economic uncertainty and delayed economic recovery, ShoreMaster, revised its sales and operating cash flow projections downward in the second quarter of 2010, 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 ShoreMaster impairment charges on operating results for the nine months ended September 30, 2010 is shown in the following table:

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

Intersegment Eliminations—Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the nine month periods ended September 30, 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)		Nine Months Ended September 30, 2010		Nine Months Ended September 30, 2009
Operating Revenues:				
Electric	$	166	$	162
Nonelectric		3,423		3,300
Cost of Goods Sold		2,888		3,228
Other Nonelectric Expenses		701		234

Electric

(in thousands)	Nine Months Ended September 30, 2010	2009	Change	% Change
Retail Sales Revenues	$ 224,794	$ 206,395	$ 18,399	8.9
Wholesale Revenues – Company Generation	16,506	10,178	6,328	62.2
Net Revenue – Energy Trading Activity	2,765	3,375	(610)	(18.1)
Other Revenues	12,067	12,809	(742)	(5.8)
Total Operating Revenues	$ 256,132	$ 232,757	$ 23,375	10.0
Production Fuel	55,611	43,585	12,026	27.6
Purchased Power – System Use	32,730	40,362	(7,632)	(18.9)
Other Operation and Maintenance Expenses	84,365	79,216	5,149	6.5
Depreciation and Amortization	30,111	27,001	3,110	11.5
Property Taxes	7,222	6,939	283	4.1
Operating Income	$ 46,093	$ 35,654	$ 10,439	29.3

The increase in retail sales revenues mainly is due to the following: (1) a $7.4 million increase in revenues due to a 1.3% increase in retail kwh sales as a result of a 86.7% increase in cooling degree days between the periods, as well as rate design changes implemented pursuant to recent rate case decisions, (2) a $3.3 million increase in Minnesota renewable resource recovery and transmission rider revenues, (3) a $2.2 million increase in North Dakota renewable resource recovery rider revenues, (4) a $1.5 million increase in revenues related to a general rate increase in South Dakota which began in May 2009, (5) $1.4 million related to a Minnesota interim rate increase effective May 2010, (6) a $1.4 million increase in Minnesota CIP surcharge revenues, (7) a $0.5 million increase in fuel cost recovery revenues, and (8) 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 57.1% increase in wholesale kwh sales, combined with a 3.2% increase in the average price per kwh sold. Generating plant output was 23.3% higher in the first nine months of 2010 than in the first nine months of 2009, in part 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, decreased mainly as a result of a decrease in net settlements recognized on forward purchases and sales of electricity entered into in 2010 compared with contracts entered into in the first nine months of 2009. The decrease in other electric revenues reflect a $1.1 million refund for excess overhead charged by OTP to the Big Stone II participants and a $1.0 million reduction in revenue from services provided to other entities, mainly Big Stone II transmission permitting work for the Midwest Independent System Operator (MISO) in 2009, partially offset by a $1.3 million increase in MISO tariff revenue for transmission services.

The increase in fuel costs is due to a 22.3% increase in kwhs generated from OTP’s fuel-fired plants combined with a 4.3% increase in the cost of fuel per kwh generated. The decrease in purchased power – system use is due to a 36.4% decrease in kwhs purchased for retail sales, partially offset by a 27.4% 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 and dispatch of all of OTP’s coal-fired plants in 2010.

The increase in other operation and maintenance expenses is due to the following: (1) a $3.3 million increase in labor costs, mainly related to increased wage and benefit costs and a decrease in capitalized labor between the periods, (2) a $1.4 million increase in Minnesota CIP recognized program costs, (3) a $0.5 million increase in insurance costs, mainly due to increases in storm repair expenses and costs to insure OTP's Luverne Wind Farm assets, (4) a $0.5

million increase in tree-trimming expenses, (5) a $0.5 million increase in dues and subscription expenses, mostly for software maintenance fees, and (6) a $0.5 million increase in amortization of deferred rate case and plant abandonment costs, offset by (7) a $1.3 million decrease in costs incurred to provide contracted services to others.

The increases in depreciation expense and property taxes are 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)	Nine Months Ended September 30, 2010	2009	Change	% Change
Operating Revenues	$ 76,562	$ 63,066	$ 13,496	21.4
Cost of Goods Sold	66,710	58,097	8,613	14.8
Operating Expenses	4,028	3,759	269	7.2
Depreciation and Amortization	2,417	2,100	317	15.1
Operating Income (Loss)	$ 3,407	$ (890)	$ 4,297	482.8

Operating revenues for the plastics segment increased as result of a 2.6% increase in pounds of PVC pipe sold combined with an 18.5% increase in the price per pound of PVC pipe sold related to a 27.6% increase in PVC resin costs between the periods. The increase in costs of goods sold was related to the increase in pounds of PVC pipe sold combined with a 12.0% increase in the cost per pound of pipe sold, which was also driven by the increase in PVC resin costs. 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. Expenses incurred in the third quarter of 2010 in connection with the planned relocation of production equipment from Hampton, Iowa to the plant in Fargo, North Dakota contributed to the increase in operating expenses. Asset additions in 2009 and the acceleration of amortization of leasehold improvements at the Hampton facility contributed to the increase in depreciation expense.

Manufacturing

(in thousands)	Nine Months Ended September 30, 2010	2009	Change	% Change
Operating Revenues	$ 235,403	$ 248,790	$ (13,387)	(5.4)
Cost of Goods Sold	197,644	199,782	(2,138)	(1.1)
Other Operating Expenses	28,616	28,481	135	0.5
Asset Impairment Charge	19,740	--	19,740	--
Product Recall and Testing Costs	--	1,766	(1,766)	--
Depreciation and Amortization	17,458	16,802	656	3.9
Operating (Loss) Income	$ (28,055)	$ 1,959	$ (30,014)	--

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

Revenues at DMI decreased $17.7 million as lower production levels were realized due to a different customer mix and lower productivity while supporting the deliveries to a customer contract.

Revenues at ShoreMaster decreased $9.5 million due to an $11.1 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 $1.7 million increase in sales of residential products.

Revenues at BTD increased $11.5 million due to improved customer demand, better productivity and higher scrap-metal prices.

Revenues at T.O. Plastics increased $2.3 million due to increased sales of horticultural and custom products.

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

Cost of goods sold at DMI increased $0.1 million. A reduction in costs related to production decreases was offset by $8.5 million in additional production costs incurred in 2010 to complete towers to a customer's new design specifications and to support the customer's delivery schedule for completed towers.

Cost of goods sold at ShoreMaster decreased $8.2 million mainly due to the decrease in sales of commercial products, but also due to $1.8 million in additional costs incurred on a commercial project in 2009.

Cost of goods sold at BTD increased $5.0 million as a result of a $7.2 million increase in labor, material and overhead costs related to higher sales volumes, mitigated by a $2.2 million reduction in costs due to productivity improvements and sales of higher cost finished goods inventory in the first quarter of 2009.

Cost of goods sold at T.O. Plastics increased $0.9 million as a result of a $1.5 million increase in labor, material and overhead costs related to higher sales volumes, mitigated by a $0.6 million reduction in costs due to productivity improvements.

The increase 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.

Other operating expenses at ShoreMaster increased $0.9 million between the periods mainly due to an increase in its provision for uncollectible accounts in 2010.

Other operating expenses at BTD decreased $0.5 million mainly as a result of costs incurred in the first nine months of 2009 to implement a management program designed to improve productivity across the organization. No similar costs were incurred in the first nine months of 2010.

Other operating expenses at T.O. Plastics increased $0.5 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)	Nine Months Ended September 30, 2010	2009	Change	% Change
Operating Revenues	$ 73,116	$ 83,412	$ (10,296)	(12.3)
Cost of Goods Sold	55,590	66,828	(11,238)	(16.8)
Operating Expenses	13,115	14,801	(1,686)	(11.4)
Depreciation and Amortization	4,050	2,934	1,116	38.0
Operating Income (Loss)	$ 361	$ (1,151)	$ 1,512	131.4

Revenues from scanning and other related services decreased $10.3 million as a result of a 17.3% decrease in scans performed, partially offset by a 1.5% increase in revenue per scan. Revenues from equipment sales and servicing were flat between the periods. The decrease in costs of goods sold reflects a $3.2 million reduction in material, labor and other direct and indirect costs of sales and a reduction in equipment rental costs of $8.0 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. Through this process, the imaging business has reduced the combined number of units of imaging equipment it leases and owns by 16.4% over the past twelve months. The decrease in operating expenses includes a $0.8 million reduction in sales and marketing salaries and expenses, $0.6 million related to an increase in gains on sales assets and a $0.3 million reduction in labor and travel costs. 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)	Nine Months Ended September 30, 2010	2009	Change	% Change
Operating Revenues	$ 56,648	$ 59,358	$ (2,710)	(4.6)
Cost of Goods Sold	41,594	44,195	(2,601)	(5.9)
Operating Expenses	2,883	2,592	291	11.2
Depreciation and Amortization	3,552	3,313	239	7.2
Operating Income	$ 8,619	$ 9,258	$ (639)	(6.9)

The decrease in food ingredient processing revenues is due to a 0.9% decrease in pounds of product sold, combined with a 3.7% decrease in the price per pound of product sold. The decrease in cost of goods sold reflects a 5.0% 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 increases in sales and marketing and bad debt expenses. The increase in depreciation expense is related to 2009 and 2010 capital additions.

Other Business Operations

(in thousands)	Nine Months Ended September 30, 2010	2009	Change	% Change
Operating Revenues	$ 118,776	$ 97,615	$ 21,161	21.7
Cost of Goods Sold	75,843	63,924	11,919	18.6
Operating Expenses	41,968	34,745	7,223	20.8
Depreciation and Amortization	2,006	1,826	180	9.9
Operating Loss	$ (1,041)	$ (2,880)	$ 1,839	63.9

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

Revenues at Foley Company increased $12.2 million due to the initiation of work on a few large projects in 2010.

Revenues at Wylie increased $9.6 million as a result of a 19.6% increase in miles driven by company-owned and owner-operated trucks combined with a 10.5% increase in revenue per mile driven and a $2.7 million increase in revenue from brokerage activity. The increase in miles driven reflects increased demand for flatbed services for transporting steel, agricultural equipment and mineral extraction equipment. The increase in revenues per mile driven reflects higher freight rates and price increases for fuel cost recovery related to a 27.6% increase in the average cost per gallon of fuel consumed.

Revenues at Aevenia decreased $0.6 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 $12.9 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 $1.0 million, mainly due to a reduction in work volume.

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

Operating expenses at Wylie increased $6.4 million as a result of increases of $3.4 million in contractor and brokerage settlements, $1.2 million in fuel costs, $0.8 million in repairs and maintenance costs and $0.6 million in labor, travel and insurance costs. These expense increases were due to the 19.6% increase in miles driven by company-owned and owner-operated trucks combined with a 27.6% increase in the average cost per gallon of fuel consumed and a 21.8% increase in brokerage miles.

Operating expenses at Foley Company increased $0.7 million between the periods mainly for salaries, maintenance and supplies.

Operating expenses at Aevenia increased $0.2 million due to an increase in advertising and promotional expenses.

Corporate

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

(in thousands)	Nine Months Ended September 30, 2010	2009	Change	% Change
Operating Expenses	$ 11,331	$ 9,376	$ 1,955	20.9
Depreciation and Amortization	397	289	108	37.4

The increase in corporate operating expenses includes severance costs related to personnel changes in the third quarter of 2010 and increased expenses for employee benefits and contracted services.

Other Income

Other income decreased $0.5 million in the first nine months of 2010 compared with the first nine months of 2009 as a result of: (1) a $2.9 million decrease in allowance for equity funds used during construction related to a decrease in construction work in progress at OTP as a result of not having a major project under construction in 2010 similar to the Luverne Wind Farm project in 2009 and (2) a $0.7 million increase in foreign currency transaction losses incurred in the Canadian operations of DMI related to fluctuations in foreign currency exchange rates between the Canadian and U.S. dollar, offset by (3) a $2.3 million increase in Minnesota CIP accrued incentives at OTP, (4) a $0.5 million investment loss in the third quarter of 2009, and (5) $0.3 million in carrying charges accrued related to the settlement of the North Dakota portion of Big Stone II plant abandonment costs.

Interest Charges

Interest charges increased $7.4 million in the first nine months of 2010 compared with the first nine months of 2009 as a result of a $58.5 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 $1.1 million reduction in capitalized interest mainly related to a reduction in construction work in progress at OTP, and a $0.7 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 $6.7 million to the increase in interest expenses, and the retirement of the remaining $58 million of the $75 million Luverne Term Note in January 2010 reduced interest expenses by $1.7 million between the periods.

Income Taxes

Income tax benefits increased $1.5 million in the first nine months of 2010 compared with the first nine months of 2009, mainly as a result of a $13.2 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 $0.1 million decrease in PTCs and North Dakota wind energy credits related to OTP's wind projects.

Our effective income tax rates for the nine months ended September 30, 2010 and 2009 were approximately 51.0% and (13.3%), 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 $5.6 million in the first nine 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 nine months of 2009, we recorded PTCs and North Dakota wind energy credits totaling $5.5 million on $15.6 million of income before income taxes, which contributed to the negative tax rate for the nine months ended September 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 September 30, 2010 and December 31, 2009:

(in thousands)	Line Limit	In Use on September 30, 2010	Restricted due to Outstanding Letters of Credit	Available on September 30, 2010	Available on December 31, 2009
Otter Tail Corporation Credit Agreement	$ 200,000	$ 61,000	$ 2,024	$ 136,976	$ 179,755
OTP Credit Agreement	170,000	32,854	250	136,896	167,735
Total	$ 370,000	$ 93,854	$ 2,274	$ 273,872	$ 347,490

OTP borrowed $20.0 million on its credit facility in September 2010 to make a discretionary contribution to its pension fund. That contribution increases our 2009 taxable loss. Tax provisions allow that loss to be carried back against previous years' income taxes, which will result in an additional tax refund in 2010 of approximately $8.0 million.

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, but will automatically renew for two consecutive 12-month periods and can continue to renew up to 60 months if neither party terminates the agreement. The minimum notice period for termination is two months. Currently, DMI does not intend to terminate the agreement. Accounts receivable totaling $44.1 million were sold in the first nine months of 2010. Discounts, fees and commissions charged to operating expense for the nine months ended September 30, 2010 and 2009 were $152,000 and $304,000, respectively. The balance of receivables sold that was outstanding to the buyer as of September 30, 2010 was $8.6 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 $60.9 million for the nine months ended September 30, 2010 compared with cash provided by operating activities of $140.6 million for the nine months ended September 30, 2009. The $79.7 million decrease in operating cash flow is mainly due to a net increase in accounts receivable of $49.0 million in the first nine months of 2010 due to increased business activity compared with a net decrease in accounts receivable of $30.0 million in the first nine months 2009. In the first nine months 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 and accounts payable were being reduced. In the first nine months of 2010, accounts receivable increased significantly 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 $29.3 million decrease in interest payable and income taxes receivable in the first nine months of 2010. We recorded an additional income tax refund receivable of approximately $8.0 million in September 2010 related to OTP’s $20.0 million pension fund contribution. We expect to receive that refund prior to the end of 2010.

Net cash used in investing activities was $61.8 million for the nine months ended September 30, 2010 compared with $166.2 million for the nine months ended September 30, 2009. Cash used for capital expenditures decreased by $87.3 million between the periods mainly due to a decrease in capital expenditures of $95.4 million in the electric segment related to OTP's 2009 Luverne Wind Farm expenditures. Capital expenditure decreases in the manufacturing segment of $10.6 million, mainly related to capital additions at DMI and BTD in the first nine months of 2009, were more than offset by a $16.3 million increase in capital expenditures in the health services segment. Capital expenditures in the first nine months of 2010 include $28.8 million at OTP for expenditures across all plant categories and $18.5 million in the health services segment, mainly for the purchase of imaging assets coming off lease.

Net cash used in financing activities was $3.3 million for the nine months ended September 30, 2010 compared with net cash provided by financing activities of $25.1 million for the nine months ended September 30, 2009. Proceeds from short-term borrowings and checks written in excess of cash were $91.2 million in the first nine months of 2010 compared to a net reduction in short-term borrowings of $12.4 million in the first nine months of 2009. Proceeds from the issuance of long-term debt were $0.1 million in the first nine months of 2010 compared with $75.0 million in the first nine months of 2009 used to finance construction of 33 wind turbines at the Luverne Wind Farm. We paid $59.2 million to retire long-term debt in the first nine months of 2010 compared with $6.0 million in the same period of 2009. Proceeds from short-term borrowings and checks written in excess of cash of $91.2 million in the first nine months of 2010 were used to retire early a portion of the remaining $58 million of the $75 million in long-term debt used to finance construction of 33 wind turbines at the Luverne Wind Farm, to finance capital expenditures in the first nine months of 2010 and to fund a $20.0 million discretionary contribution to our pension fund in September 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 $64.2 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 "Other Purchase Obligations" have increased by $3.6 million in 2010 and $23.4 million in 2011 related to IPH's potato supply and fuel purchase agreements entered into in September 2010 and OTP's CapX2020 project commitments approved by our Board of Directors in the third quarter of 2010.

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 OTP’s $90 million 6.63% senior notes due December 1, 2011, as amended (the 2001 Note Purchase Agreement), the note purchase agreement relating to our $50 million 8.89% senior note due November 30, 2017, as amended (the Cascade Note Purchase Agreement), and the note purchase agreement relating to OTP’s $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 September 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. As of September 30, 2010 our interest coverage ratio calculated under the requirements of the Credit Agreement was 1.61 to 1.00.

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. As of September 30, 2010 our interest coverage ratio calculated under the requirements of the Cascade Note Purchase Agreement was 1.52 to 1.00.

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. As of September 30, 2010 our interest coverage ratio calculated under the requirements of the OTP Credit Agreement was 3.01 to 1.00.

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. As of September 30, 2010 our interest coverage ratio calculated under the requirements of both the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement was 3.01 to 1.00.

As of September 30, 2010 our interest-bearing debt to total capitalization was 0.45 to 1.00 on a fully consolidated basis and 0.50 to 1.00 for OTP.

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 narrowing our 2010 diluted earnings per share guidance from our previously announced range of $0.70 to $1.00 to a range of $0.70 to $0.85, primarily reflecting the near-term challenges facing DMI. While certain circumstances, such as further gradual economic improvement in certain industrial sectors and seasonal conditions in our electric business, may enable us to achieve diluted earnings per share (EPS) toward the upper end of this range, we currently expect to generate 2010 diluted EPS below the midpoint of the narrowed range. The guidance ranges above exclude the $0.49 per share effects of the asset impairment and health care reform charges recorded in the first half of 2010. On a GAAP basis, the narrowed range is $0.21 to $0.36 per share including the effect of the above-mentioned charges. 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.

Segment components of our 2010 guidance range are as follows:

	Previous EPS Range	EPS Range
Electric*	$0.89 to $0.96	$1.00 to $1.02
Plastics	$0.02 to $0.04	$0.03 to $0.04
Manufacturing**	($0.05) to $0.05	($0.26) to ($0.20)
Health Services	$0.00 to $0.02	$0.00 to $0.01
Food Ingredient Processing	$0.16 to $0.19	$0.20 to $0.22
Other Business Operations	($0.01) to $0.03	$0.00 to $0.01
Corporate	($0.31) to ($0.29)	($0.27) to ($0.25)
Total Range	$0.70 to $1.00	$0.70 to $0.85

*The electric earnings per share guidance ranges from $0.95 to $0.97 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 ($0.70) to ($0.64) 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 now expect 2010 electric segment net income to be slightly ahead of 2009 as a result of increases in retail and wholesale revenues and CIP bonus incentives offsetting lower AFUDC earnings and increased operating and maintenance expense in 2010. Expectations for 2010 reflect an interim rate increase of approximately $2.9 million in revenue in the Minnesota jurisdiction. Otter Tail Power Company’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 $0.9 million to $1.5 million.

We now expect our manufacturing segment to post a net loss 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.

- o We 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.

- o We expect DMI to have a net loss in 2010. This is driven by additional production costs incurred in the second and third quarters to meet a customer's design specifications and delivery schedule on a new tower design. Reductions in projected business volumes for the year have also contributed to the expected net loss at DMI. Deliveries on one contract have been deferred into 2011 and projected demand for towers in 2010 has been lower than anticipated. The American Wind Energy Association has reported significantly lower wind installations in 2010 compared with 2009.

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

- o Backlog in place in the manufacturing segment is approximately $56 million for the remainder of 2010 compared with $61 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 $7.0 million to $8.0 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 $48 million for the remainder of 2010 compared with $25 million one year ago.

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

Fourth Quarter 2010 Segment Realignment
Effective October 1, 2010, we realigned our business structure and defined our operating segments to be consistent with our business strategy and based on the reporting and review process used by our chief decision makers. Our revised reporting segments, which will be reported in our 2010 Annual Report, are as follows:

Corporate will continue to be reported separately along with our reportable business segments in order to reconcile our reportable business segments with our consolidated assets, net income and cash flows.

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.

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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 September 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 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 nine months 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. BTD continues to perform ahead of 2010 budgeted levels of revenues and net earnings.

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 healthcare 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.

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, or to meet covenants under our borrowing agreements.

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.

We made a $20.0 million discretionary contribution to our pension plan in 2010. If the market value of pension plan assets declines in the future as it did in 2008 or does not increase as projected and relief under the Pension Protection Act is no longer granted, the corporation could be required to contribute additional capital to the pension plan in future years.

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.

We are subject to risks and uncertainties related to the timing of recovery of deferred tax assets which could have a negative impact on our net income in future periods.

Certain of our operating companies sell products to consumers that could be subject to recall.

Competition is a factor in all of our businesses.

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 September 30, 2010 OTP had $8.0 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.

The U.S. wind industry is reliant on tax and other economic incentives and political and governmental policies. A significant change in these incentives and policies could negatively impact our results of operations and growth.

We are substantially dependent on a few significant customers in our wind tower manufacturing business.

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 September 30, 2010 we had exposure to market risk associated with interest rates because we had $61.0 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 $32.9 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 September 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 15.8% of IPH sales in the first nine months 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 October 1, 2010 through December 31, 2010 by entering into forward foreign currency exchange contracts. On September 30, 2010 IPH’s Canadian subsidiary held contracts for the exchange of $1,500,000 USD for $1,563,000 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 September 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 September 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 September 30, 2010 OTP had recognized, on a pretax basis, $829,000 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 September 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 September 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 September 30, 2010 and the change in our consolidated balance sheet position from December 31, 2009 to September 30, 2010:

(in thousands)	Year-to-Date September 30, 2010
Fair Value at Beginning of Year	$ 1,030
Less: Amount Realized on Contracts Entered into in 2009 and Settled in 2010	308
Changes in Fair Value of Contracts Entered into in 2009	--
Net Fair Value of Contracts Entered into in 2009 at End of Period	722
Changes in Fair Value of Contracts Entered into in 2010	107
Net Fair Value End of Period	$ 829

The $829,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on September 30, 2010 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	4th Quarter 2010	2011	2012	Total
Net Gain	$ 200	$ 308	$ 321	$ 829

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 September 30, 2010 was $277,000. As of September 30, 2010 OTP had a net credit risk exposure of $815,000 from eleven counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. OTP had no exposure at September 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 $815,000 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 September 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 September 2010 for firm purchases of natural gas to cover portions of its anticipated natural gas needs in Ririe, Idaho through September 2011 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 September 30, 2010:

(in thousands)	Settlement Periods	USD	CAD
Contracts entered into in May 2010	October 2010 - December 2010	$ 1,500	$ 1,563

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 sheet as of September 30, 2010, and the change in the Company's consolidated balance sheet position from December 31, 2009 to September 30, 2010:

(in thousands)		September 30, 2010	
Fair Value of IPH Foreign Currency Exchange Forward Windows included in:			
Other Current Assets	$	--	
Other Accrued Current Liabilities		(16	)
Net Fair Value of Foreign Currency Exchange Forward Windows	$	(16	)

(in thousands)		Year-to-Date September 30, 2010	
Fair Value at Beginning of Year	$	--	
Changes in Fair Value of Contracts Entered into in 2010		(16	)
Net Fair Value End of Period	$	(16	)

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 September 30, 2010 were valued and marked to market on September 30, 2010 based on quoted exchange values on September 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 September 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 September 30, 2010.

During the fiscal quarter ended September 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. On August 12, 2010 the Court of Appeals affirmed the District Court's decision dismissing the Sierra Club complaint. The Sierra Club did not file a petition for rehearing with the Court of Appeals. The deadline for a petition for writ of certiorari with the U.S. Supreme Court is November 10, 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

The Company is adding three risk factors to 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.

We are subject to risks and uncertainties related to the timing of recovery of deferred tax assets which could have a negative impact on our net income in future periods.

If taxable income is not generated in future periods in certain tax jurisdictions the recovery of deferred taxes related to accumulated tax benefits may be delayed and we may be required to record a reserve related to the uncertainty of the timing of recovery of deferred tax assets related to accumulated taxable losses in those tax jurisdictions. This would have a negative impact on the Company’s net income in the period the reserve is recorded.

The U.S. wind industry is reliant on tax and other economic incentives and political and governmental policies. A significant change in these incentives and policies could negatively impact our results of operations and growth.

Our wind tower manufacturing business is focused on supplying towers to wind turbine manufacturers and owners and operators of wind energy generation facilities. The wind industry is dependent on federal tax incentives and state renewable portfolio standards and may not be economically viable absent such incentives.

The federal government provides economic incentives to the owners of wind energy facilities, including a federal production tax credit, an investment tax credit and a cash grant equal in value to the investment tax credit. These programs provide material incentives to develop wind energy generation facilities and thereby impact the demand for our manufactured products and services. The failure of Congress to extend or renew these incentives beyond their current expiration dates could significantly delay the development of wind energy generation facilities and the demand for wind turbines, towers, gearing and related components. We cannot assure you that any extension or renewal of the production tax credit, investment tax credit or cash grant program will be enacted prior to its expiration or, if allowed to expire, that any extension or renewal enacted thereafter would be enacted with retroactive effect. Any delay or failure to extend or renew the federal production tax credit, investment tax credit or cash grant program in the future could have a material adverse impact on our business, results of operations and future financial performance.

State renewable energy portfolio standards generally require or encourage state-regulated electric utilities to supply a certain proportion of electricity from renewable energy sources or devote a certain portion of their plant capacity to renewable energy generation. These standards have spurred significant growth in the wind energy industry and a corresponding increase in the demand for our manufactured products. Currently, the majority of states and the District of Colombia have renewable energy portfolio standards in place and certain other states have voluntary utility commitments to supply a specific percentage of their electricity from renewable sources. Any changes to existing renewable energy portfolio standards, the enactment of renewable energy portfolio standards in additional states, or the enactment of a federal renewable energy portfolio may impact the demand for our products. We cannot assure you that government support for renewable energy will continue. The elimination of, or reduction in, state or federal government policies that support renewable energy could have a material adverse impact on our business, results of operations and future financial performance.

We are substantially dependent on a few significant customers in our wind tower manufacturing business.

The wind turbine market in the United States is concentrated, with eight manufacturers controlling in excess of 97% of the market. In addition, the majority of revenues in our wind tower manufacturing business have been highly concentrated with a limited number of customers. These customers were adversely affected by the downturn in the economy and we have seen, and may continue to see, a decrease in order volume from such customers. In addition, our customers have sought, and in the future may seek, to renegotiate the terms of contractual agreements. Among other things, contractual disputes could lead to an overall decrease in such customer's demand for our products and services, difficulty in collecting amounts due for such products or services, or difficulty in collecting amounts due to one or more of our subsidiaries that are not related to the dispute. A material change in payment terms for accounts receivable of a significant customer could have a material adverse effect on our short-term cash flows. We could also experience a reduction in demand if any of our customers determine to become more vertically integrated and produce our products internally. If our relationship with any of our significant customers should change materially, it could be difficult for us to immediately and profitably replace lost sales in a market with such concentration, which would materially adversely affect our results.

There have been no other material changes 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.

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Item 6. Exhibits

4.1 Amendment No. 4 dated as of July 24, 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 August 3, 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.

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

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

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: November 8, 2010

EXHIBIT INDEX

Exhibit Number	Description
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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.