Otter Tail Corp
Form 10-Q
November 09, 2009

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

(Mark One)

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

For the quarterly period ended September 30, 2009

OR

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

For the transition period from __________ to __________

Commission file number 0-53713

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 þ NO o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

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

October 31, 2009 35,689,751 Common Shares ($5 par value)

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2009	December 31, 2008
	(Thousands of dollars)	
Current Assets		
Cash and Cash Equivalents	$ 6,066	$ 7,565
Accounts Receivable:		
Trade Net	111,737	136,609
Other	8,731	13,587
Inventories	84,000	101,955
Deferred Income Taxes	8,411	8,386
Accrued Utility and Cost-of-Energy Revenues	10,572	24,030
Costs and Estimated Earnings in Excess of Billings	44,141	65,606
Income Taxes Receivable	9,200	26,754
Other	20,086	8,519
Total Current Assets	302,944	393,011
Investments	9,019	7,542
Other Assets	42,979	22,615
Goodwill	106,778	106,778
Other Intangibles Net	34,279	35,441
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	9,488	7,247
Regulatory Assets and Other Deferred Debits	98,813	82,384
Total Deferred Debits	108,301	89,631
Plant		
Electric Plant in Service	1,322,059	1,205,647
Nonelectric Operations	350,147	321,032
Total Plant	1,672,206	1,526,679
Less Accumulated Depreciation and Amortization	588,527	548,070
Plant Net of Accumulated Depreciation and Amortization	1,083,679	978,609
Construction Work in Progress	50,024	58,960
Net Plant	1,133,703	1,037,569

Total	$ 1,738,003	$ 1,692,587

See accompanying notes to consolidated financial statements

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

	September 30, 2009	December 31, 2008
	(Thousands of dollars)	
Current Liabilities		
Short-Term Debt	$ 122,500	$ 134,914
Current Maturities of Long-Term Debt	1,275	3,747
Accounts Payable	100,142	113,422
Accrued Salaries and Wages	21,476	29,688
Accrued Taxes	10,092	10,939
Other Accrued Liabilities	16,130	12,034
Total Current Liabilities	271,615	304,744
Pensions Benefit Liability	79,781	80,912
Other Postretirement Benefits Liability	34,076	32,621
Other Noncurrent Liabilities	21,641	19,391
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	116,705	123,086
Deferred Tax Credits	48,297	34,288
Regulatory Liabilities	66,855	64,684
Other	829	397
Total Deferred Credits	232,686	222,455
Capitalization		
Long-Term Debt, Net of Current Maturities	411,309	339,726
Class B Stock Options of Subsidiary	1,220	1,220
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2009 and 2008 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 2009 35,683,339 and 2008 35,384,620	178,417	176,923
Premium on Common Shares	246,948	241,731
Retained Earnings	245,836	260,364
Accumulated Other Comprehensive Loss	(1,026)	(3,000)
Total Common Equity	670,175	676,018

Total Capitalization	1,098,204	1,032,464
Total	$ 1,738,003	$ 1,692,587

See accompanying notes to consolidated financial statements

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Otter Tail Corporation
Consolidated Statements of Income
(not audited)

	Three months ended September 30, 2009	Three months ended September 30, 2008	Nine months ended September 30, 2009	Nine months ended September 30, 2008
	(In thousands, except share and per share amounts)		(In thousands, except share and per share amounts)	
Operating Revenues				
Electric	$ 73,506	$ 82,821	$ 232,595	$ 248,904
Nonelectric	183,934	270,098	548,941	727,852
Total Operating Revenues	257,440	352,919	781,536	976,756
Operating Expenses				
Production Fuel Electric	13,172	18,732	43,585	53,444
Purchased Power Electric System Use	11,112	10,456	40,362	39,598
Electric Operation and Maintenance Expenses	23,327	33,091	79,216	87,591
Cost of Goods Sold Nonelectric (depreciation included below)	141,318	213,999	429,598	583,457
Other Nonelectric Expenses	30,476	37,222	93,520	108,211
Product Recall and Testing Costs			1,766	
Plant Closure Costs		883		2,295
Depreciation and Amortization	18,345	16,563	54,265	47,600
Property Taxes Electric	2,194	2,227	6,939	7,414
Total Operating Expenses	239,944	333,173	749,251	929,610
Operating Income	17,496	19,746	32,285	47,146
Other Income	1,609	1,157	3,627	2,745
Interest Charges	7,358	7,269	20,280	21,023
Income Before Income Taxes	11,747	13,634	15,632	28,868
Income Taxes	1,155	4,003	(2,079)	7,490
Net Income	10,592	9,631	17,711	21,378
Preferred Dividend Requirements	184	184	552	552
Earnings Available for Common Shares	$ 10,408	$ 9,447	$ 17,159	$ 20,826
Earnings Per Common Share:				
Basic	$ 0.29	$ 0.31	$ 0.48	$ 0.69
Diluted	$ 0.29	$ 0.31	$ 0.48	$ 0.69

Average Number of Common Shares Outstanding:				
Basic	35,528,190	30,513,578	35,413,893	30,108,381
Diluted	35,788,293	30,817,013	35,670,244	30,398,235
Dividends Per Common Share	$ 0.2975	$ 0.2975	$ 0.8925	$ 0.8925

See accompanying notes to consolidated financial statements

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

	Nine Months Ended September 30, 2009	2008
	(Thousands of dollars)	
Cash Flows from Operating Activities		
Net Income	$ 17,711	$ 21,378
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	54,265	47,600
Deferred Tax Credits	(1,666)	(1,180)
Deferred Income Taxes	8,243	9,123
Change in Deferred Debits and Other Assets	(2,909)	(2,162)
Discretionary Contribution to Pension Plan	(4,000)	(2,000)
Change in Noncurrent Liabilities and Deferred Credits	7,497	1,795
Allowance for Equity (Other) Funds Used During Construction	(2,940)	(1,712)
Change in Derivatives Net of Regulatory Deferral	(1,512)	(337)
Stock Compensation Expense	2,664	2,885
Other Net	736	580
Cash Provided by (Used for) Current Assets and Current Liabilities:		
Change in Receivables	29,993	(24,314)
Change in Inventories	18,721	(9,054)
Change in Other Current Assets	29,329	(8,165)
Change in Payables and Other Current Liabilities	(32,506)	4,997
Change in Interest and Income Taxes Payable/Receivable	16,953	810
Net Cash Provided by Operating Activities	140,579	40,244
Cash Flows from Investing Activities		
Capital Expenditures	(150,138)	(172,237)
Proceeds from Disposal of Noncurrent Assets	4,730	7,446
Acquisitions Net of Cash Acquired		(41,674)
Net Increase in Other Investments and Long-Term Assets	(20,805)	(393)
Net Cash Used in Investing Activities	(166,213)	(206,858)
Cash Flows from Financing Activities		
Net Short-Term Borrowings	(12,414)	16,955
Proceeds from Issuance of Common Stock	4,637	162,961
Common Stock Issuance Expenses	(23)	(6,136)
Payments for Retirement of Common Stock	(229)	(91)
Proceeds from Issuance of Long-Term Debt	75,005	1,140
Short-Term and Long-Term Debt Issuance Expenses	(3,693)	(527)
Payments for Retirement of Long-Term Debt	(5,983)	(2,691)
Dividends Paid	(32,239)	(27,382)

Net Cash Provided by Financing Activities	25,061	144,229
Effect of Foreign Exchange Rate Fluctuations on Cash	(926)	423
Net Change in Cash and Cash Equivalents	(1,499)	(21,962)
Cash and Cash Equivalents at Beginning of Period	7,565	39,824
Cash and Cash Equivalents at End of Period	$ 6,066	$ 17,862

See accompanying notes to consolidated financial statements

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

On July 1, 2009, Otter Tail Corporation completed a holding company reorganization whereby Otter Tail Power Company (OTP), which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation (formerly known as Otter Tail Holding Company). The new parent holding company (now known as Otter Tail Corporation) was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization. References in this report to Otter Tail Corporation and the Company refer, for periods prior to July 1, 2009, to the corporation that was the registrant prior to the reorganization, and, for periods after the reorganization, to the new parent holding company, in each case including its consolidated subsidiaries, unless otherwise indicated or the context otherwise requires.

In the opinion of management, the Company has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated results of operations for the periods presented. The consolidated financial statements and notes thereto should be read in conjunction with the consolidated financial statements and notes as of and for the years ended December 31, 2008, 2007 and 2006 included in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2008. Because of seasonal and other factors, the earnings for the three-month and nine-month periods ended September 30, 2009 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, 2008.

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 OTP s forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with 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 27.4% for the three months ended September 30, 2009 compared with 34.6% for the three months ended September 30, 2008 and 27.5% for the nine months ended September 30, 2009 compared with 32.3% for the nine months ended September 30, 2008. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company s wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at any point in time during a contract, a projected loss for the entire contract is estimated and recognized.

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

(in thousands)	September 30, 2009	December 31, 2008
Costs Incurred on Uncompleted Contracts	$ 406,010	$ 377,237
Less Billings to Date	(426,825)	(366,931)
Plus Estimated Earnings Recognized	61,364	47,355
	$ 40,549	$ 57,661

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, 2009	December 31, 2008
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 44,141	$ 65,606
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(3,592)	(7,945)
	$ 40,549	$ 57,661

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI) were $36,509,000 as of September 30, 2009 and $59,300,000 as of December 31, 2008. 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 $9,061,000 on September 30, 2009 and $10,311,000 on December 31, 2008.

Sales of Receivables

DMI has a $40 million receivables purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement expires in March 2011. Accounts receivable totaling $114.5 million have been sold in 2009. Discounts and commissions and fees of $37,000 for the three months ended September 30, 2009 and $304,000 for the nine months ended September 30, 2009 were charged to operating expenses in the consolidated statements of income. 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 manufacturer, provides dealer floor plan financing assistance for certain dealer purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer s order. ShoreMaster recognizes the estimated cost of projected interest payments related to each financed sale as a liability and a reduction of revenue at the time of sale, based on historical experience of the average length of time floor plan debt is outstanding, in accordance with 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 were $75,000 for the three months ended September 30, 2009 and $308,000 for the nine months ended September 30, 2009 compared with $98,000 for the three months ended September 30, 2008 and $338,000 for the nine months ended September 30, 2008.

Supplemental Disclosures of Cash Flow Information

	Nine Months Ended September 30,	
(in thousands)	2009	2008
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$9,535	$(21,117)

Fair Value Measurements

Effective January 1, 2008, the Company adopted ASC 820, *Fair Value Measurements and Disclosures*, for recurring fair value measurements. ASC 820 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 are as follows:

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

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

Level 3 Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation 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, 2009:

(in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Investments for Nonqualified Retirement Savings Retirement Plan:				
Money Market, Mutual Funds and Cash	$ 690	$	$	$ 690
Cash Surrender Value of Life Insurance Policies		10,650		10,650
Cash Surrender Value of Keyman Life Insurance Policies Net of Policy Loans		10,911		10,911
Forward Energy Contracts		6,241		6,241
Forward Foreign Currency Exchange Contracts	120			120
Investments of Captive Insurance Company:				
Corporate Debt Securities	6,427			6,427
U.S. Government Debt Securities	656			656
Total Assets	$7,893	$27,802	$	$35,695
Liabilities:				
Forward Energy Contracts	$	$ 7,232	$	$ 7,232
Asset Retirement Obligations			3,880	3,880
Total Liabilities	$	$ 7,232	$ 3,880	$11,112
Net Assets (Liabilities)	$7,893	$20,570	$(3,880)	$24,583

Inventories

Inventories consist of the following:

(in thousands)	September 30, 2009	December 31, 2008
Finished Goods	$ 36,311	$ 38,943
Work in Process	5,128	10,205
Raw Material, Fuel and Supplies	42,561	52,807
Total Inventories	$ 84,000	$ 101,955

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Other Intangible Assets

The following table summarizes the components of the Company s intangible assets at September 30, 2009 and December 31, 2008:

September 30, 2009 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Covenants Not to Compete	$ 2,190	$ 1,992	$ 198	3 5 years
Customer Relationships	26,942	3,381	23,561	15 25 years
Other Intangible Assets Including Contracts	2,358	1,719	639	5 30 years
Total	$ 31,490	$ 7,092	$ 24,398	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,881	$	$ 9,881	
December 31, 2008 *(in thousands)*				
Amortized Intangible Assets:				
Covenants Not to Compete	$ 2,250	$ 1,889	$ 361	3 5 years
Customer Relationships	26,854	2,429	24,425	15 25 years
Other Intangible Assets Including Contracts	2,710	1,921	789	5 30 years
Total	$ 31,814	$ 6,239	$ 25,575	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,866	$	$ 9,866	

The amortization expense for these intangible assets was $1,250,000 for the nine months ended September 30, 2009 compared to $1,023,000 for the nine months ended September 30, 2008. The estimated annual amortization expense for these intangible assets for the next five years is $1,643,000 for 2009, $1,461,000 for 2010, $1,332,000 for 2011, $1,312,000 for 2012 and $1,308,000 for 2013.

Comprehensive Income

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2009	2008	2009	2008
Net Income	$ 10,592	$ 9,631	$ 17,711	$ 21,378
Other Comprehensive Gain (Loss) (net-of-tax):				
Foreign Currency Translation Gain (Loss)	1,119	(579)	1,703	(954)
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	88	37	192	117

Unrealized Gain (Loss) on Available-for-Sale Securities	53	(83)	79	(118)
Total Other Comprehensive Gain (Loss)	1,260	(625)	1,974	(955)
Total Comprehensive Income	$11,852	$9,006	$19,685	$20,423

New Accounting Standards

SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162*, was issued by the Financial Accounting Standards Board (FASB) in June 2009. SFAS No. 168 confirms that the FASB ASC is the single source of authoritative generally accepted accounting principles in the United States, other than guidance put forth by the Securities and Exchange Commission. All other accounting literature not included in the ASC will be considered non-authoritative. SFAS No. 168 is effective for interim and annual periods ending after September 15, 2009. References to accounting standards in this and future filings will be to applicable standards in the ASC or to applicable code sections within the ASC.

Business Combinations In December 2007, the FASB issued new guidance on business combinations that applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The new guidance, under ASC 805, *Business Combinations,* applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term purchase method of accounting with acquisition method of accounting, ASC 805 requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance replaces previous guidance on the cost-allocation process, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. The new guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, prior guidance required the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. The new guidance requires those costs to be expensed as incurred. In addition, under previous guidance, restructuring costs that the acquirer expected but was not obligated to incur were recognized as if they were a liability assumed at the acquisition date. The new guidance requires the acquirer to recognize those costs separately from the business combination. The Company adopted the new guidance on business combinations on January 1, 2009. The adoption did not have a material impact on its consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities In March 2008, the FASB issued new guidance on disclosures about derivative instruments and hedging activities. The new guidance under ASC 815, *Derivatives and Hedging,* requires enhanced disclosures about an entity s derivative and hedging activities to improve the transparency of financial reporting and is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company adopted the new guidance on January 1, 2009. Adoption of the new guidance resulted in additional footnote disclosures related to the Company s use of derivative instruments, the location and fair value of derivatives reported on the Company s consolidated balance sheets, the location and amounts of derivative instrument gains and losses reported on the Company s consolidated statements of income and information on credit risk exposure related to derivative instruments.

Employers Disclosures about Postretirement Benefit Plan Assets In December 2008, the FASB issued new guidance on Employers Disclosures about Pensions and Other Postretirement Benefits. The new guidance under ASC 715-20 *Defined Benefit Plans General,* expands an employer s required disclosures about plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, information regarding fair value measurements, and significant concentrations of credit risk. The new guidance is effective for fiscal years ending after December 15, 2009. The Company does not expect the adoption of the new guidance to have a material impact on its consolidated financial statements.

Interim Disclosures about Fair Value of Financial Instruments In April 2009, the FASB issued new guidance on disclosures about fair value of financial instruments to require disclosures regarding the fair value of financial instruments in interim financial statements. The new disclosure requirements under ASC 825, *Financial Instruments,* are effective for interim periods ending after June 15, 2009. The Company implemented the new guidance on April 1, 2009. The implementation did not have a material impact on the Company s consolidated financial statements. ASC 825 required disclosures have been included in the Company s notes to consolidated financial statements, where applicable.

Subsequent Events In May 2009, the FASB issued new guidance regarding subsequent events. The new guidance under ASC 855, *Subsequent Events,* establishes general standards of accounting and disclosure for events that occur after the balance sheet date but before financial statements are issued. The new accounting guidance is consistent with the auditing literature widely used for accounting and disclosure of subsequent events, however, the new guidance requires an entity to disclose the date through which subsequent events have been evaluated. The new guidance is effective for interim and annual periods ending after June 15, 2009. The Company implemented the new guidance on April 1, 2009. The implementation did not have a material impact on the Company s consolidated financial statements.

SFAS No. 167, *Amendments to FASB Interpretation No. 46(R),* was issued by the FASB in June 2009. SFAS No. 167 amends the consolidation guidance applicable to variable interest entities. The amendments will significantly affect various elements of consolidation guidance under FASB Interpretation No. 46(R), including guidance for determining whether an entity is a variable interest entity and whether an enterprise is the primary beneficiary of a variable interest entity. SFAS No. 167 is effective for fiscal years beginning after November 15, 2009. The Company does not expect the implementation of SFAS No. 167 to have a significant impact on its consolidated financial statements. SFAS No. 167 will remain authoritative until it is integrated into the ASC.

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2. Segment Information

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

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

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

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

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

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

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

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

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

No single external customer accounted for 10% or more of the Company s revenues in the nine months ended September 30, 2009. 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,	
	2009	2008	2009	2008
United States of America	97.7%	97.9%	97.9%	97.1%
Canada	0.7%	1.1%	0.9%	1.3%
All Other Countries (none greater than 1%)	1.6%	1.0%	1.2%	1.6%

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The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for three and nine month periods ended September 30, 2009 and 2008 and total assets by business segment as of September 30, 2009 and December 31, 2008 are presented in the following tables:

Operating Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2009	2008	2009	2008
Electric	$ 73,553	$ 82,883	$232,757	$249,139
Plastics	27,353	36,690	63,066	99,685
Manufacturing	75,928	127,778	248,790	345,715
Health Services	27,053	31,139	83,412	91,144
Food Ingredient Processing	18,691	15,333	59,358	47,144
Other Business Operations	36,123	59,650	97,615	145,840
Corporate Revenues and Intersegment Eliminations	(1,261)	(554)	(3,462)	(1,911)
Total	$257,440	$352,919	$781,536	$976,756

Interest Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2009	2008	2009	2008
Electric	$5,380	$3,158	$13,657	$ 9,272
Plastics	181	369	580	838
Manufacturing	1,346	2,659	4,064	7,035
Health Services	108	176	304	531
Food Ingredient Processing	9	46	29	87
Other Business Operations	118	331	350	933
Corporate and Intersegment Eliminations	216	530	1,296	2,327
Total	$7,358	$7,269	$20,280	$21,023

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2009	2008	2009	2008
Electric	$ 1,419	$ 1,863	$ 2,358	$ 8,017
Plastics	896	1,088	(553)	1,942
Manufacturing	236	288	(776)	303
Health Services	(395)	208	(471)	(218)
Food Ingredient Processing	1,068	(717)	3,406	497
Other Business Operations	(141)	2,908	(1,291)	2,291

Corporate	(1,928)	(1,635)	(4,752)	(5,342)
Total	$ 1,155	$ 4,003	$(2,079)	$ 7,490

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Earnings Available for Common Shares

(in thousands)	Three Months Ended September 30, 2009	2008	Nine Months Ended September 30, 2009	2008
Electric	$ 9,527	$ 6,335	$22,080	$21,993
Plastics	1,298	1,641	(869)	2,913
Manufacturing	100	380	(1,157)	1,160
Health Services	(649)	254	(875)	(525)
Food Ingredient Processing	1,772	(1,074)	5,544	734
Other Business Operations	(205)	4,341	(1,986)	3,370
Corporate	(1,435)	(2,430)	(5,578)	(8,819)
Total	$10,408	$ 9,447	$17,159	$20,826

Total Assets

(in thousands)	September 30, 2009	December 31, 2008
Electric	$1,100,142	$ 992,159
Plastics	72,298	78,054
Manufacturing	298,228	356,697
Health Services	58,526	61,086
Food Ingredient Processing	89,117	88,813
Other Business Operations	65,033	71,359
Corporate	54,659	44,419
Total	$1,738,003	$1,692,587

3. Rate and Regulatory Matters

Minnesota

General Rate Case 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 rates and final rates, with interest, in March 2009. OTP deferred recognition of $1.5 million in rate case-related filing and administrative costs in June 2008 that are subject to amortization and recovery over a three year period beginning in February 2009.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need (MegaCON) On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt (kv) transmission lines. Evidentiary hearings for the Certificate of Need for the three CapX 2020 345-kv transmission line projects began in July 2008 and continued into August 2008. On April 16, 2009 the MPUC approved by a 5-0 vote the MegaCON for the three 345-kv Group 1 CapX 2020 line projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Twin Cities-LaCrosse). The MPUC then voted 3-2 to impose conditions pertaining to reserving line capacity for renewable energy sources on the Brookings line project. The MPUC did take up reconsideration of the original order regarding the conditions.

Upon deliberation, the MPUC slightly modified the conditions on the Brookings line. As part of the MegaCON approval, the MPUC accepted a CapX 2020 request to build the 345-kv lines for double-circuit capability to have two 345-kv transmission circuits on each structure. The current plan is to string only one circuit. The MegaCON orders were appealed to the Minnesota Court of Appeals on October 9, 2009. Route permit applications were filed for the Brookings project in late December 2008 and for the Monticello to St. Cloud portion of the Fargo project in April 2009. The route permit for the St. Cloud to Fargo portion of the Fargo Project was filed on October 1, 2009. Portions of the projects would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are completed, construction will begin.

The lines would be expected to be completed over a two to four year period. Great River Energy and Xcel Energy are leading these projects, and OTP and eight other utilities are involved in permitting, building and financing. OTP is directly involved in two of these three 345-kv projects.

OTP serves as the lead utility in a fourth CapX 2020 Group 1 project, the Bemidji-Grand Rapids 230-kv line, which has an expected in-service date of 2012-2013. OTP filed a Certificate of Need (CON) for this fourth project on March 17, 2008. The Department of Commerce Office of Energy Security (MNOES) staff completed briefing papers regarding the Bemidji-Grand Rapids route permit application. The MNOES staff recommended to the MPUC: (1) the route permit application be found to be complete, (2) the need determination not be sent to a contested case but be handled informally by MPUC review, and (3) the Certificate of Need and route permit proceedings be combined as requested. The MPUC met on June 26, 2008 to act on the MNOES staff recommendation. The MPUC agreed the Certificate of Need and route permit applications were complete. The MNOES subsequently recommended a determination that need for the line has been established. The Environmental Report for the CON was issued in April 2009. CON hearings were conducted on May 20 and May 21, 2009 and a summary of comments was issued on June 8, 2009. The CON was issued on July 9, 2009 and the written order received on July 14, 2009. The Applicants continue to work with the MNOES to define the schedule for issuance of the Draft Environmental Impact Statement and the Route Contested Case Hearing. The Route Hearing is expected in early 2010. The MPUC is expected to determine the route for this line and, if appropriate, issue a route permit in mid-2010. A federal Environmental Impact Statement also will be needed for this project.

Renewable Energy Standards, Conservation, Renewable Resource and Transmission Riders In February 2007, the Minnesota legislature passed a renewable energy standard requiring 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. Additionally, Minnesota law requires utilities to make a good faith effort to generate or procure sufficient renewable generation such that 7% of total retail electric sales to retail customers in Minnesota comes from qualifying renewable sources by 2010. 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. By the end of 2010, OTP expects to have sufficient renewable energy resources available 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 passed by the Minnesota legislature in May 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover investments and costs incurred to satisfy the requirements of the renewable energy standards. The MPUC is now authorized to approve a rate schedule rider to enable utilities to recover the costs of qualifying renewable energy projects that supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can now be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

In an order issued on August 15, 2008, the MPUC approved OTP s proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in 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. The first renewable energy project for which OTP is receiving cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008.

OTP s 2009 MNRRA filing includes a request for recovery of its investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008. The MPUC acted on OTP s petition for a 2009 MNRRA in July 2009 approving an MNRRA of $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 and for accrued renewable resource recovery revenues not recovered through billings by March 31, 2010, recovery was granted over a 48-month period beginning in April 2010. OTP has recognized a regulatory asset of $5.3 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of September 30, 2009. OTP has requested that the MPUC determine whether its Luverne Wind Project is eligible for cost recovery through the MNRRA. The annual MNRRA cost recovery filing will be made by December 31, 2009 with a requested effective date of April 1, 2010.

In addition to the Renewable Resource Cost Recovery Rider, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new electric transmission facilities. The MPUC may approve a rider rate schedule to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need proceeding or certified by the MPUC as a Minnesota priority transmission project or investment and expenditures made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility s retail customers. Such transmission cost recovery riders would allow a return on investments at the level approved in a utility s last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. A request for approval of a transmission cost recovery rider was filed with the MPUC on July 28, 2009. On October 19, 2009 OTP responded to comments filed by the MNOES and the Minnesota Chamber of Commerce. The matter is now pending MPUC approval. As of September 30, 2009 OTP had accrued $0.4 million in revenues probable of recovery through the transmission cost recovery rider when approved.

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. The North Dakota Public Service Commission s (NDPSC) order authorizing an interim rate increase requires OTP to refund North Dakota customers the difference between final and interim rates, with interest, if final rates approved by the NDPSC are lower than interim rates. A tentative settlement of all issues in the case, joined by all applicable parties and the NDPSC advocacy staff, was filed with the NDPSC in June 2009. As of November 6, 2009 the NDPSC had not approved the settlement or granted a final rate increase. Interim rates will remain in effect for all North Dakota customers until the NDPSC makes its final determination. OTP established a refund reserve for revenues collected under interim rates that exceed the revenue increase agreed to in the tentative settlement, plus interest. The refund reserve balance was $0.7 million as of September 30, 2009.

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 40.5 megawatt ownership share of 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 has 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 being processed in combination with OTP s General Rate Case, the NDPSC is reviewing whether to move the costs of the projects currently being recovered through the rider into base rate cost recovery and whether to make changes to the rider. Settlement negotiations related to the general rate case and the NDRRA are expected to reduce the NDRRA for the period from final rates until the effective date for the next annual NDRRA filing. The interim reduced rate will be calculated when the date for final rates is known, but is expected to be between $0.0035 and $0.0040 per kwh. Because the 2008 annual NDRRA filing was combined with the general rate case proceedings, which have not yet concluded, the 2009 annual filing to establish the 2010 NDRRA rate, which includes cost recovery for OTP s investment in its Luverne Wind Project, has been delayed until December 31, 2009, with a requested effective date of April 1, 2010.

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 are eligible for recovery through the NDRRA. Terms of the proposed 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, 2009 consolidated balance sheet includes a regulatory asset of $1.1 million for revenues that are eligible for recovery through the NDRRA but have not been billed to North Dakota customers as of September 30, 2009.

CAPX 2020 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). The NDPSC is required by law to render an order on the application no later than seven months after the application was filed. An order determining prudence is binding for ratemaking purposes.

South Dakota

General Rate Case 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 includes recovery of renewable resource investments and expenses in base rates. OTP increased rates by approximately 11.7% on a temporary basis beginning with electricity consumed on and after May 1, 2009, as allowed by South Dakota statutes. In an order issued by the South Dakota Public Utilities Commission on June 30, 2009 OTP was granted an increase in South Dakota retail electric rates of $2.9 million or approximately 11.7%. OTP implemented final, approved rates in July 2009.

Haze Best Available Retrofit Technology (BART) Rule On June 15, 2005 the Environmental Protection Agency (EPA) signed the BART rule. The rule requires emissions reductions from designated sources that are deemed to contribute to visibility impairment in Class I air quality areas. The Big Stone Plant is potentially subject to emission reduction requirements. At the request of the South Dakota Department of Environment and Natural Resources (DENR), OTP agreed to model Big Stone emissions to evaluate the impact of plant emissions on Class I air quality areas. The modeling effort was completed and the final report submitted to the DENR on March 19, 2008. The report was not acceptable to all parties and DENR requested that OTP submit a BART modeling protocol that was acceptable to DENR, EPA, and other federal land management agencies. OTP submitted a modeling protocol in June 2009 and committed to making certain changes to the protocol in August 2009. On September 18, 2009 DENR approved the modeling protocol and on November 2, 2009 OTP submitted to DENR its analysis of what control technology should be considered BART for nitrogen oxides, sulfur dioxide, and particulate matter for the Big Stone Plant. In that filing, OTP estimated the cost of BART technologies to be approximately $146 million for Big Stone I (OTP owns 53.9% of the facility). It is not yet known whether the proposed control technology will be approved or required by the DENR.

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 on the paper hearing 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 FERC s earlier decision to remove the words actually withdraws energy (AWE) from the RSG tariff provisions. Absent this relief (or waiver), the removal of the AWE language would have had two relevant impacts on the RSG charge: (1) it would tend to reduce the RSG rate because the rate denominator would include all virtual supply volumes and (2) it would impose RSG charges on all cleared virtual supply transactions. The waiver applies to the period August 10, 2007 through November 9, 2008. Beginning November 10, 2008, the Midwest ISO 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 is currently undertaking that review and plans to file the results in early December. Whether other mismatches or rate changes must be resettled will not be determined until the FERC issues additional orders. The Company does not know when these litigation proceedings will conclude.

Federal Clean Air Act (the Act) In 1998 the EPA announced its New Source Review Enforcement Initiative targeting coal-fired utilities, petroleum refineries, pulp and paper mills and other industries for alleged violations of the EPA s New Source Review rules. These rules require owners or operators that construct new major sources or make major modifications to existing sources to obtain permits and install air pollution control equipment at affected facilities. The EPA is attempting to determine if emission sources violated certain provisions of the Act by making major modifications to their facilities without installing state-of-the-art pollution controls. On January 2, 2001 OTP received a request from the EPA, pursuant to Section 114(a) of the Act, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant. OTP responded to that request. In March 2003 the EPA conducted a review of the plant s outage records as a follow-up to their January 2001 data request. A copy of the designated documents was provided to the EPA on March 21, 2003. On January 8, 2009, OTP received another request from EPA Regions 5 and 8, pursuant to Section 114(a) of the Act, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant, Coyote Station and Hoot Lake Plant. OTP filed timely responses to the EPA s requests on February 23, 2009 and March 31, 2009. In July 2009, EPA Region 5 issued a follow-up information request with respect to certain maintenance and repair work at the Hoot Lake Plant. OTP responded to the request. At this time, OTP cannot determine what, if any, actions will be taken by the EPA.

The Act calls for EPA studies of the effects of emissions of listed pollutants by electric steam generating plants. The EPA has completed the studies and submitted reports to Congress. The Act required the EPA to make a finding as to whether regulation of emissions of hazardous air pollutants from fossil fuel-fired electric utility generating units is appropriate and necessary. On December 14, 2000 the EPA announced it affirmatively decided to regulate mercury emissions from electric generating units. The EPA published the proposed mercury rule on January 30, 2004. The proposal included two options for regulating mercury emission from coal-fired electric generating units. One option would set technology-based maximum achievable control technology standards under paragraph 111(d) of the Act. The other option embodied a market-based cap and trade approach to emissions reduction. The EPA published final rules in May 2005 based on the cap and trade approach. On October 28, 2005 the EPA announced a reconsideration of portions of the final rules. Final rules were published on June 9, 2006 that maintained the cap and trade approach. On February 8, 2008 the United States Court of Appeals for the D.C. Circuit granted petitions for review of the EPA rules and vacated the rules that would have allowed the EPA to regulate mercury emissions based on a cap and trade approach. On March 14, 2008 the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating the EPA final rule regulating utility mercury emissions. The EPA had appealed the court s decision to the U.S. Supreme Court, but withdrew its appeal in early 2009. The Supreme Court denied the appeals of other parties to the litigation on February 23, 2009. The EPA rulemaking is slated to proceed under the maximum achievable control technologies (MACT) provision of the Clean Air Act section 112(d) for existing units and section 112(g) case-by-case MACT provisions for affected new units. The EPA has recently agreed to a settlement of litigation about the timing of issuance of the utility MACT standard which would require that a standard be proposed in early 2011 and adopted in November 2011. OTP anticipates that the MACT standard will require installation of control technology at its power plants, but cannot determine what will ultimately be required to meet the EPA s final standard.

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. The three primary agreements were the Participation Agreement, the Operation and

Maintenance Agreement and the Joint Facilities Agreement (the latter of which expired on January 1, 2009 pursuant to a provision in the agreement).

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, including the broad economic downturn, coupled with a high level of uncertainty associated with proposed federal climate legislation and existing federal environmental regulations that resulted in challenging credit and equity markets, that 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. As a result of its withdrawal, OTP is no longer a party to the Big Stone II Participation Agreement and the Big Stone II Operation and Maintenance Agreement. As of September 30, 2009, OTP had incurred $13.6 million in costs related to this project. OTP believes these incurred costs are probable of recovery in future rates and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve OTP s rates. However, 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.

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, 2009	December 31, 2008
Regulatory Assets:		
Unrecognized Prior Service Costs and Actuarial Losses on Pension Benefits	$ 63,618	$64,490
Unrecovered Project Costs Big Stone II	13,624	
Deferred Income Taxes	6,042	7,094
Minnesota Renewable Resource Rider Accrued Revenues	5,297	3,045
Deferred Marked-to-Market Losses	3,616	1,162
Debt Reacquisition Premiums	3,118	3,357
Accumulated ARO Accretion/Depreciation Adjustment	1,679	1,437
Minnesota General Rate Case Recoverable Expenses	1,339	1,457
North Dakota Renewable Resource Rider Accrued Revenues	1,140	2,009
Deferred Conservation Improvement Program Costs	715	280
MISO Schedule 16 and 17 Deferred Administrative Costs ND	617	823
Minnesota Transmission Rider Accrued Revenues	400	
MISO Schedule 16 and 17 Deferred Administrative Costs MN	320	526
Deferred Holding Company Formation Costs	233	
South Dakota Asset-Based Margin Sharing Shortfall	142	
Accrued Cost-of-Energy Revenue	46	8,982
Plant Acquisition Costs	30	63
Total Regulatory Assets	$101,976	$94,725
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs Net of Salvage	$ 59,424	$58,768
Deferred Income Taxes	4,432	4,943
Deferred Marked-to-Market Gains	1,645	
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Gains on Other Postretirement Benefits	1,206	834

Other Regulatory Liabilities	148	139
Total Regulatory Liabilities	$ 66,855	$ 64,684
Net Regulatory Asset Position	$ 35,121	$ 30,041

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The regulatory asset related to prior service costs and actuarial losses on pension benefits and the regulatory liability related to the unrecognized transition obligation, prior service costs and actuarial gains on other postretirement benefits represents benefit costs and actuarial gains subject to recovery or return through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial gains 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.

Unrecovered Project Costs Big Stone II are costs incurred by OTP since 2005 related to its participation in the planned construction of a 500- to 600-megawatt generating unit at its Big Stone Plant site. On September 11, 2009 OTP announced its withdrawal from participation in the Big Stone II project due to a number of factors, including the broad economic downturn, coupled with a high level of uncertainty associated with proposed federal climate legislation and existing federal environmental regulations that resulted in challenging credit and equity markets, that 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. OTP believes the costs it incurred during its participation in the project are probable of recovery in future rates and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve OTP s rates. No recovery period has been established for these deferred costs as OTP is in the initial phase of seeking recovery of these costs through the regulatory process. 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.

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*.

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, 2009. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over 54 months, from October 2009 through March 2014.

All Deferred Marked-to-Market Gains and Losses recorded as of September 30, 2009 are related to forward purchases of energy scheduled for delivery through April 2013.

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

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

Minnesota General Rate Case Recoverable Expenses will be recovered over the next 28 months.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of September 30, 2009. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over 51 months, from October 2009 through January 2014.

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

MISO Schedule 16 and 17 Deferred Administrative Costs ND will be recovered over the next 27 months.

Minnesota Transmission Rider Accrued Revenues are expected to be recovered over the next 15 months.

MISO Schedule 16 and 17 Deferred Administrative Costs MN will be recovered over the next 14 months.

Deferred Holding Company Formation Costs will be amortized over the next 57 months.

South Dakota Asset-Based Margin Sharing Shortfall represents a difference in OTP s South Dakota share of actual profit margins on wholesale sales of electricity from company-owned generating units and estimated profit margins from those sales that were used in determining current South Dakota retail electric rates. Net shortfalls or excess margins accumulated over 14 months will be subject to recovery or refund through future retail rate adjustments in South Dakota.

Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next 23 months.

Plant Acquisition Costs will be amortized over the next 8 months.

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

Other Regulatory Liabilities includes: 1) a portion of profit margins on wholesales sales of purchased power subject to refund to South Dakota customers through future retail rate adjustments and 2) a deferred gain on the sale of utility property that will be paid to Minnesota retail electric customers over the next 25 years.

If for any reason, OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of their operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an extraordinary expense or income item in the period in which the application of guidance under of 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, 2009 OTP had recognized, on a pretax basis, $980,000 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 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. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in 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, 2009 and December 31, 2008, and the change in the Company s consolidated balance sheet position from December 31, 2008 to September 30, 2009:

(in thousands)	September 30, 2009	December 31, 2008
In Other Current Assets Marked-to-Market Gain	$ 6,241	$ 405
In Regulatory Assets and Other Deferred Debits Deferred Marked-to-Market Loss	3,616	1,162
In Other Accrued Current Liabilities Marked-to-Market Loss	(7,232)	(1,690)
In Regulatory Liabilities Deferred Marked-to-Market Gain	(1,645)	

Net Fair Value of Marked-to-Market Energy Contracts	$	980	$	(123)

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(in thousands)	Year-to-Date September 30, 2009
Fair Value at Beginning of Year	$ (123)
Less: Amount Realized on Contracts Entered into in 2008 and Settled in 2009	123
Changes in Fair Value of Contracts Entered into in 2008	
Net Fair Value of Contracts Entered into in 2008 at End of Period	
Changes in Fair Value of Contracts Entered into in 2009	980
Net Fair Value End of Period	$ 980

Realized and unrealized net gains (losses) on forward energy contracts of $956,000 for the three months ended September 30, 2009, $2,130,000 for the nine months ended September 30, 2009, $65,000 for the three months ended September 30, 2008 and $2,284,000 for the nine months ended September 30, 2008 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 purchases and sales agreements. OTP has established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty s financial strength. The credit risk with the largest counterparty on delivered and marked-to-market forward contracts as of September 30, 2009 was $1,910,000. As of September 30, 2009 the net credit risk exposure was $2,602,000 from nine counterparties with investment grade credit ratings and two counterparties that have not been rated by an external credit rating agency but have been evaluated internally and assigned an internal credit rating equivalent to investment grade. OTP had no exposure at September 30, 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 $2,602,000 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, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $96,000 on certain of OTP s derivative energy contracts included in the $7,232,000 derivative liability on September 30, 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 are in a liability position on September 30, 2009 is $3,614,000, for which OTP has posted $3,601,000 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 September 30, 2009, OTP would be required to post $13,000 in additional collateral to its counterparties. The remaining derivative liability balance of $3,522,000 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 and fuel oil, IPH entered into contracts with its fuel suppliers in August 2008 and January 2009 for firm purchases of natural gas and fuel oil to cover portions of its anticipated natural gas needs in Ririe, Idaho and Center, Colorado from September 2008 through August 2009 and its fuel oil needs in Souris, Prince Edward Island, Canada from January 2009 through August 2009 at fixed prices. These contracts qualified 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 2008. Each monthly contract was for the exchange of $400,000 U.S. dollars for the amount of Canadian dollars stated in each contract. IPH s Canadian subsidiary also entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in July 2009. Each monthly contract was for the exchange of $200,000 U.S. dollars for the amount of Canadian dollars stated in each contract.

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The following table lists the contracts outstanding as of September 30, 2009:

(in thousands)	Settlement Period	USD	CAD
Contracts entered into in October 2008	October 2009	$ 400	$ 467
Contracts entered into in July 2009	October 2009 December 2009	600	653
Contracts outstanding on September 30, 2009	October 2009 December 2009	$1,000	$1,120

The following tables show the effect of marking to market IPH s foreign currency exchange forward windows and the location and fair value amounts of the related derivatives reported on the Company s consolidated balance sheets as of September 30, 2009 and December 31, 2008, and the change in the Company s consolidated balance sheet position from December 31, 2008 to September 30, 2009:

(in thousands)	September 30, 2009	December 31, 2008
Fair Value of IPH Foreign Currency Exchange Forward Windows included in:		
Other Current Assets	$ 120	$
Other Accrued Current Liabilities		(289)
Net Fair Value of Foreign Currency Exchange Forward Windows	$ 120	$ (289)

(in thousands)	Year-to-Date September 30, 2009
Fair Value at Beginning of Year	$ (289)
Less: Amount Realized on Contracts Entered into in 2008 and Settled in 2009	229
Changes in Fair Value of Contracts Entered into in 2008	127
Net Fair Value of Contracts Entered into in 2008 at End of Period	67
Changes in Fair Value of Contracts Entered into in 2009	53
Net Fair Value End of Period	$ 120

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, 2009 were valued and marked to market on September 30, 2009 based on quoted exchange values on September 30, 2009. Realized and unrealized net gains on IPH s foreign currency exchange forward windows of $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.

The fair value measurements of the above foreign currency exchange forward windows fall into level 1 of the fair value hierarchy set forth in ASC 820-10-35.

6. Common Shares and Earnings Per Share

On May 11, 2009 the Company filed a shelf registration statement with the U.S. Securities and Exchange Commission (SEC) under which it may offer for sale, from time to time, either separately or together in any combination, equity and/or debt securities described in the shelf registration statement, including common shares of the Company.

On July 1, 2009 Otter Tail Corporation completed a holding company reorganization in accordance with Section 302A.626 of the Minnesota Business Corporation Act (the MBCA) whereby OTP (also referred to as Old Otter Tail), which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation (formerly known as Otter Tail Holding Company).

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The new holding company structure was effected as of July 1, 2009 pursuant to a Plan of Merger dated as of June 30, 2009 (the Plan of Merger), by and among Old Otter Tail, Otter Tail Holding Company (now known as Otter Tail Corporation), a Minnesota corporation and, prior to the reorganization a direct subsidiary of Old Otter Tail, and Otter Tail Merger Sub Inc., a Minnesota corporation and indirect subsidiary of Old Otter Tail and direct subsidiary of Otter Tail Holding Company (Merger Sub). The Plan of Merger provided for the merger (the Merger) of Old Otter Tail with Merger Sub, with Old Otter Tail as the surviving corporation. Pursuant to Section 302A.626 (subd. 2) of the MBCA shareholder approval was not required for the Merger. As a result of the Merger, Old Otter Tail is now a wholly owned subsidiary of the Company with the name Otter Tail Power Company. Immediately following the completion of the Merger, the Company changed its name from Otter Tail Holding Company to Otter Tail Corporation.

In the Merger, each issued and outstanding common share of Old Otter Tail was converted into one common share of the Company, par value $5 per share, and each issued and outstanding cumulative preferred share of Old Otter Tail was converted into one cumulative preferred share of the Company having the same designations, rights, powers and preferences. In connection with the Merger, each person that held rights to purchase, or other rights to or interests in, common shares of Old Otter Tail under any stock option, stock purchase or compensation plan or arrangement of Old Otter Tail immediately prior to the Merger holds a corresponding number of rights to purchase, and other rights to or interests in, common shares of the Company, par value $5 per share, immediately following the Merger.

The conversion of the common shares in the Merger occurred without an exchange of certificates. Accordingly, certificates formerly representing outstanding common shares of Old Otter Tail are deemed to represent the same number of common shares of the Company.

Pursuant to Section 302A.626 (subd. 7) of the MBCA, the provisions of the Restated Articles of Incorporation and Restated Bylaws of the Company are consistent with those of Old Otter Tail prior to the Merger. The authorized common shares and cumulative preferred shares of the Company, the designations, rights, powers and preferences of such shares and the qualifications, limitations and restrictions thereof are also consistent with those of Old Otter Tail s common shares and cumulative preferred shares immediately prior to the Merger. The directors and executive officers of the Company are the same individuals who were directors and executive officers, respectively, of Old Otter Tail immediately prior to the Merger.

Immediately prior to the Merger, Old Otter Tail transferred to the Company by means of assignment the capital stock of its direct subsidiaries and all of its other assets not specific to the operation of the OTP. As a result, the Company is a holding company with two primary subsidiaries, OTP and Varistar Corporation.

Following is a reconciliation of the Company s common shares outstanding from December 31, 2008 through September 30, 2009:

Common Shares Outstanding, December 31, 2008	35,384,620
Issuances:	
Dividend Reinvestment Plan Dividend Purchases	110,466
Dividend Reinvestment Plan Direct Purchases	49,223
Employee Stock Purchase Plan Direct Purchase	45,413
Executive Officer Stock Performance Awards	29,350
Restricted Stock Issued to Nonemployee Directors	28,800
Restricted Stock Issued to Employees	27,600
Employee Stock Purchase Plan Dividend Reinvestment	11,350
Vesting of Restricted Stock Units	5,350
Stock Options Exercised	1,350
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(10,183)
Common Shares Outstanding, September 30, 2009	35,683,339

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

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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, 2009 and 2008:

Three Months Ended September 30,	Options Outstanding	Range of Exercise Prices
2009	415,710	$24.93 $31.34
2008		NA

Nine Months Ended September 30,	Options Outstanding	Range of Exercise Prices
2009	415,710	$24.93 $31.34
2008		NA

7. Share-Based Payments

The Company has five share-based payment programs.

On April 20, 2009 the Company s Board of Directors granted 29,515 restricted stock units to key employees under the 1999 Stock Incentive Plan, as amended (Incentive Plan), payable in common shares on April 8, 2013, the date the units vest. The grant date fair value of each restricted stock unit was $18.86 per share determined under a Monte Carlo valuation method based on the market value of the Company s common stock on April 20, 2009.

On April 20, 2009 the Company s Board of Directors granted 28,800 shares of restricted stock to the Company s nonemployee directors and 27,600 shares of restricted stock to the Company s executive officers under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2010 through 2013 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $22.15 per share, the average market price on the date of grant.

On April 20, 2009 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 181,200 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, 2009 through December 31, 2011. The aggregate target share award is 90,600 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 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, 2009 the remaining unrecognized compensation expense related to stock-based compensation was approximately $7.0 million (before income taxes) which will be amortized over a weighted-average period of 2.2 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, 2009 and 2008 are presented in the table below:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2009	2008	2009	2008
Employee Stock Purchase Plan (15% discount)	$ 76	$ 75	$ 238	$ 210
Restricted Stock Granted to Directors	141	110	395	350

Restricted Stock Granted to Employees	118	102	320	341
Restricted Stock Units Granted to Employees	141	149	410	387
Stock Performance Awards Granted to Executive Officers	712	562	1,934	1,686
Totals	$1,188	$998	$3,297	$2,974

9. Commitments and Contingencies

OTP Coal Contract

In March 2009, OTP entered into an agreement for the purchase of coal to cover a portion of its current coal requirements in 2009 and 2010 with a minimum purchase commitment totaling approximately $9,500,000. The Fuel Clause Adjustment mechanism in retail electric rates lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

OTP Capacity and Energy Agreement

In May 2009, OTP entered into an agreement for the purchase of 50 megawatts of capacity and associated energy from a regional power producer from May 1, 2010 through April 30, 2013 to cover a portion of its expected energy requirements during that period at a cost of approximately $36.5 million over the three-year term of the agreement. At its sole discretion, OTP has until November 30, 2009 to cancel years two and three of the agreement.

Dealer Floor Plan Financing

Under ShoreMaster s floor plan financing agreement with GE Commercial Distribution Finance Corporation (CDF), ShoreMaster is required to repurchase new and unused inventory repossessed from ShoreMaster s dealers by CDF to satisfy dealer obligations to CDF. ShoreMaster has agreed to unconditionally guarantee to CDF all current and future liabilities which any dealer owes to CDF under this agreement. Any amounts due under this guaranty will be payable despite impairment or unenforceability of CDF s security interest with respect to inventory that may prevent CDF from repossessing the inventory. The aggregate total of amounts owed by dealers to CDF under this agreement was $1.9 million on September 30, 2009. ShoreMaster has incurred no losses under this agreement. The Company believes current available cash and cash generated from operations provide sufficient funding in the event there is a requirement to perform under this agreement. CDF exercised its right under this agreement to terminate the agreement effective February 28, 2009. The termination of the agreement has no affect on ShoreMaster s obligations to CDF for any products financed, advances made or approvals granted by CDF under the agreement prior to the effective termination date. Additionally, ShoreMaster is liable for any expenses incurred by CDF after the effective termination date in connection with the collection of any amounts or other charges as set forth in the agreement.

Sierra Club Complaint

On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleged certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further 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 Clean Air Act 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 Clean Air Act and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone was and is being operated in compliance with the Clean Air Act 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. The briefing schedule calls for the appellant to submit its brief by mid-October, for appellees to submit their brief by mid-November and for the appellant to submit its reply brief by the end of November. On October 13, 2009, the United States Department of Justice filed a motion seeking a 30-day extension of the time to file an amicus brief in support of the Sierra Club s position. The Court of Appeals granted this motion, as well as the appellees subsequent joint motion with the Sierra Club, extending the time to file the appellees brief and the Sierra Club s reply brief. We anticipate briefing to be complete by the end of January 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. The parties are in the process of negotiating a formal settlement agreement to be filed with the FERC.

Product Recall

Aviva Sports, Inc. (Aviva), a subsidiary of ShoreMaster, markets a variety of consumer products to catalog companies and internet based retailers. Some of these products are regulated by the U.S. Consumer Product Safety Commission (CPSC). On February 3, 2009 Aviva received a report of consumer contacts from a catalog customer related to one of Aviva s trampoline products. Aviva has not received any personal injury claims or lawsuits related to this product. Aviva submitted notification of the complaints to the CPSC and voluntarily agreed to undertake a recall of approximately 13,000 of the trampoline products sold to consumers. ShoreMaster recorded a liability and operating expense of $1.4 million related to the recall in the first quarter of 2009. The expense includes a projected 50% response rate on the recall request, fees to the third party recall administrator, costs to destroy inventory and all legal and administration fees. Of the recalled products, 44.9% have been corrected. As of the date of this report on Form 10-Q, ShoreMaster is continuing its recall efforts and has not made a request to the CPSC to close the recall.

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, 2009 will not be material.

10. Short-Term and Long-Term Borrowings

On May 11, 2009 the Company filed a shelf registration statement with the SEC under which it may offer for sale, from time to time, either separately or together in any combination, equity and/or debt securities described in the shelf registration statement.

Term Loan Agreement

On May 22, 2009, Otter Tail Corporation, d/b/a Otter Tail Power Company (now known as OTP) entered into a $75 million Term Loan Agreement due May 2011 (the Loan Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, KeyBank National Association, as syndication agent, Union Bank, N.A., as documentation agent, and the banks named therein.

Borrowings under the Loan Agreement bear interest at a rate equal to the base rate in effect from time to time. The base rate is a fluctuating rate per annum equal to (i) the highest of (A) JPMorgan Chase Bank, N.A. s prime rate, (B) the Federal funds effective rate plus 0.5% per annum, and (C) a daily LIBOR rate plus 1.0% per annum, plus (ii) a margin of 1.5% to 3.0% determined on the basis of OTP s senior unsecured credit ratings, as provided in the Loan Agreement. At OTP s option, the interest rate on outstanding borrowings may be converted to a LIBOR rate that would fluctuate based on the rate at which deposits of U.S. dollars in the London interbank market are quoted, plus a margin of 2.5% to 4.0% determined on the basis of OTP s senior unsecured credit ratings, as provided in the Loan Agreement. OTP is using the proceeds borrowed under the Loan

Agreement to support its working capital needs and other capital requirements, including construction of the Luverne Wind Farm in North Dakota. The interest rate on borrowings under the Loan Agreement was 3.79% at September 30, 2009.

The Loan Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make certain investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Loan Agreement also contains certain financial covenants. Specifically, OTP must not permit the ratio of its Interest-bearing Debt to Total Capitalization (each as defined in the Loan Agreement) to be greater than 0.60 to 1.00, or permit its Interest and Dividend Coverage Ratio (as defined in the Loan Agreement) for any period of four consecutive fiscal quarters to be less than 1.50 to 1.00. The Loan Agreement also contains affirmative covenants and events of default. The Loan Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP s credit ratings. The obligations of OTP under the Term Loan Agreement are unsecured. Since completion of the Company s holding company formation on July 1, 2009, the Loan Agreement is an obligation of OTP.

Debt Retirement

In June 2009, the Company paid $3,493,000 to retire early its Lombard US Equipment Finance note due October 2, 2010. No penalty was paid for early retirement of the note.

Amendments to Note Purchase Agreements

In connection with Otter Tail Corporation s holding company reorganization on July 1, 2009, amendments to the following note purchase agreements were entered into in order to obtain the consent of the related noteholders to the reorganization.

<u>Fourth Amendment to 2001 Note Purchase Agreement</u>

On June 30, 2009 Otter Tail Corporation (now known as OTP) (Old Otter Tail) entered into a Fourth Amendment dated as of June 30, 2009 to Note Purchase Agreement dated as of December 1, 2001 (the Fourth Amendment) with the holders of the 2001 Notes referred to below, amending the Note Purchase Agreement dated as of December 1, 2001 among Old Otter Tail and each of the purchasers named on Schedule A attached thereto, as amended (the 2001 Note Purchase Agreement). The 2001 Note Purchase Agreement relates to the issuance and sale by Old Otter Tail, in a private placement transaction, of its $90,000,000 6.63% Senior Notes due December 1, 2011 (the 2001 Notes). The Fourth Amendment sets forth the terms and conditions of the 2001 Noteholders consent to the holding company reorganization and amends certain provisions of the 2001 Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among Old Otter Tail s note purchase agreements. These amendments include changes to negative covenants in the 2001 Note Purchase Agreement regarding limitations on liens and contingent liabilities, and to events of default. As provided in the Fourth Amendment, the 2001 Note Purchase Agreement and the 2001 Notes remained obligations of Old Otter Tail, under the name Otter Tail Power Company, following the effectiveness of the holding company reorganization. In addition, the guaranties issued by certain subsidiaries of Old Otter Tail under the 2001 Note Purchase Agreement and the 2001 Notes were released on the effectiveness of the holding company reorganization.

<u>Third Amendment to 2007 Note Purchase Agreement</u>

On June 26, 2009 Old Otter Tail entered into a Third Amendment dated as of June 26, 2009 to Note Purchase Agreement dated as of August 20, 2007 (the Third Amendment) with the holders of the 2007 Notes referred to below, amending the Note Purchase Agreement dated as of August 20, 2007 among Old Otter Tail and each of the purchasers party thereto, as amended (the 2007 Note Purchase Agreement). The 2007 Note Purchase Agreement relates to the issuance and sale by Old Otter Tail of $155 million aggregate principal amount of Old Otter Tail s Senior Unsecured Notes in four series, in the designations and aggregate principal amounts set forth in the 2007 Note Purchase Agreement (the 2007 Notes). The Third Amendment sets forth the terms and conditions of the 2007 Noteholders consent to the holding company reorganization and also amends certain provisions of the 2007 Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among Old Otter Tail s note purchase agreements. These amendments include changes to negative covenants in the 2007 Note Purchase Agreement regarding limitations on liens and subsidiary guarantees. As provided in the Third Amendment, the 2007 Note Purchase Agreement and the 2007 Notes remained obligations of Old Otter

Tail, under the name Otter Tail Power Company, following the effectiveness of the holding company reorganization.

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Amendment No. 2 to Cascade Note Purchase Agreement

On June 30, 2009 Old Otter Tail entered into an Amendment No. 2 dated as of June 30, 2009 to Note Purchase Agreement dated as of February 23, 2007 (Amendment No. 2) with Cascade Investment, L.L.C. (Cascade), amending the Note Purchase Agreement dated as of February 23, 2007 between Old Otter Tail and Cascade, as amended (the Cascade Note Purchase Agreement). The Cascade Note Purchase Agreement relates to the issuance and sale by Old Otter Tail to Cascade, in a private placement transaction, of Old Otter Tail s $50,000,000 5.778% Senior Note due November 30, 2017 (the Cascade Note). Amendment No. 2 sets forth the terms and conditions of Cascade s consent to the assignment by Old Otter Tail of its rights and obligations in, to and under the Cascade Note Purchase Agreement and the Cascade Note to Otter Tail Holding Company, the new parent holding company of Old Otter Tail that is now known as Otter Tail Corporation (the Company), effective immediately prior to the effectiveness of the holding company reorganization. Amendment No. 2 also provides for Cascade s consent to the holding company reorganization, and amends certain provisions of the Cascade Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among the Company s note purchase agreements. These amendments include changes to negative covenants in the Cascade Note Purchase Agreement regarding limitations on liens, contingent liabilities and to events of default. In addition, Amendment No. 2 provides for an additional financial covenant applicable to the Company as of the effectiveness of the holding company reorganization. Specifically, the Company may not permit the aggregate principal amount of all debt of OTP and its subsidiaries to exceed 60% of Otter Tail Consolidated Total Capitalization (as defined in the Cascade Note Purchase Agreement, as amended by Amendment No. 2), determined as of the end of each fiscal quarter of the Company. In addition, the interest rate applicable to the Cascade Note was increased to 8.89% per annum which is reflective of the Company s new senior unsecured debt ratings. The obligations of the Company under the Cascade Note Purchase Agreement and the Cascade Notes continue to be guaranteed by Varistar Corporation and certain of its subsidiaries. As provided in Amendment No. 2, the Cascade Note Purchase Agreement and the Cascade Notes became obligations of the Company immediately prior to the effectiveness of the holding company reorganization.

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, 2009.

(in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Lines of Credit	$ 14,500		$108,000	$122,500
Term Loan, Variable 3.79% at September 30, 2009, due May 20, 2011	$ 75,000			$ 75,000
Senior Unsecured Notes 6.63%, due December 1, 2011	90,000			90,000
Pollution Control Refunding Revenue Bonds, Variable, 3.25% at September 30, 2009, due December 1, 2012	10,400			10,400
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000			33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,125			5,125
Senior Unsecured Note 8.89%, due November 30, 2017			$ 50,000	50,000
	30,000			30,000

Senior Unsecured Notes 6.15%, Series B, due August 20, 2022				
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,400			20,400
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 8.25% at September 30, 2009		$7,040		7,040
Total	$355,925	$7,040	$ 50,000	$412,965
Less:				
Current Maturities		1,275		1,275
Unamortized Debt Discount		381		381
Total Long-Term Debt	$355,925	$5,384	$ 50,000	$411,309
Total Short-Term and Long-Term Debt (with current maturities)	$370,425	$6,659	$158,000	$535,084

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Financial Covenants

Following the Company s holding company reorganization on July 1, 2009 the Company s borrowing agreements are subject to certain financial covenants. Specifically:

Under the credit agreement relating to the $200 million credit facility of the Company (as assignee of Varistar Corporation), the Company 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 (each measured on a consolidated basis), as provided in the credit agreement.

Under the Cascade Note Purchase Agreement, the Company may not permit its Consolidated Debt to exceed 60% of Consolidated Total Capitalization or its Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the Debt of OTP to exceed 60% of OTP s Total Capitalization, or permit the Priority Debt of Varistar and its subsidiaries to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement.

Under the Loan Agreement and the credit agreement relating to OTP s $170 million credit facility, 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 Loan Agreement.

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

11. Class B Stock Options of Subsidiary

As of September 30, 2009 there were 772 options for the purchase of IPH Class B common shares outstanding with a combined exercise price of $391,000, of which 732 options were in-the-money with a combined exercise price of $307,000. The reduction of 140 outstanding options in 2009 is due to forfeitures related to voluntary terminations.

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)	2009	2008	2009	2008
Service Cost Benefit Earned During the Period	$ 869	$ 922	$ 3,135	$ 3,472
Interest Cost on Projected Benefit Obligation	3,008	2,894	8,958	8,494
Expected Return on Assets	(3,439)	(3,376)	(10,335)	(10,476)
Amortization of Prior-Service Cost	181	207	543	557
Amortization of Net Actuarial Loss	48	(124)	58	126
Net Periodic Pension Cost	$ 667	$ 523	$ 2,359	$ 2,173

A $4.0 million discretionary contribution was made to the pension plan in the third quarter of 2009.

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)	2009	2008	2009	2008
Service Cost Benefit Earned During the Period	$188	$172	$ 564	$ 518
Interest Cost on Projected Benefit Obligation	423	383	1,271	1,151
Amortization of Prior-Service Cost	17	18	53	50
Amortization of Net Actuarial Loss	97	120	289	360
Net Periodic Pension Cost	$725	$693	$2,177	$2,079

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)	2009	2008	2009	2008
Service Cost Benefit Earned During the Period	$ 301	$ 227	$ 903	$ 827
Interest Cost on Projected Benefit Obligation	753	567	2,259	2,017
Amortization of Transition Obligation	187	187	561	561
Amortization of Prior-Service Cost	53	58	159	158
Amortization of Net Actuarial Loss	1	(230)	3	20
Effect of Medicare Part D Expected Subsidy	(297)	(79)	(891)	(879)
Net Periodic Postretirement Benefit Cost	$ 998	$ 730	$2,994	$2,704

15. Income Taxes

The Company s effective income tax rate for the three months ended September 30, 2009 was lower than the effective tax rate for the three months ended September 30, 2008. The reduction from the federal statutory rate mainly reflects the benefit of production tax credits (PTCs) and North Dakota wind energy credits related to OTP s wind projects of approximately $1.6 million in the third quarter of 2009 compared with $0.7 million in the third quarter of 2008.

The Company s effective income tax rate for the nine months ended September 30, 2009 was lower than the effective tax rate for the nine months ended September 30, 2008. The reduction from the federal statutory rate mainly reflects the benefit of PTCs and North Dakota wind energy credits related to OTP s wind projects of approximately $5.5 million in the first nine months of 2009 compared with $2.1 million in the first nine months of 2008.

The Company recognizes PTCs as wind energy is generated and sold based on a per kilowatt-hour 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.

19. Subsequent Events

On October 27, 2009 OTP received grant proceeds of approximately $30.2 million from the U.S. Department of Treasury under the American Recovery and Reinvestment Act of 2009 related to its $100.6 million investment in thirty-three 1.5 megawatt wind turbines at its Luverne Wind Farm. OTP applied for the grant on October 1, 2009, after the wind turbines were completed and placed in service. Accounting for receipt of the proceeds will result in reductions of $30.2 million in Electric Plant in Service and Capital Expenditures on the Company s consolidated balance sheet and statement of cash flows, respectively, in the fourth quarter of 2009.

The Company has evaluated events occurring through November 6, 2009 and determined there are no other events that have occurred subsequent to September 30, 2009 that would affect the Company s consolidated financial statements as of, and for the periods ending, September 30, 2009, or require additional disclosure in this report on Form 10-Q.

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

RESULTS OF OPERATIONS

Following is an analysis of our operating results by business segment for the three and nine months ended September 30, 2009 and 2008, followed by our outlook for the remainder of 2009 and a discussion of changes in our consolidated financial position during the nine months ended September 30, 2009.

Comparison of the Three Months Ended September 30, 2009 and 2008

Consolidated operating revenues were $257.4 million for the three months ended September 30, 2009 compared with $352.9 million for the three months ended September 30, 2008. Operating income was $17.5 million for the three months ended September 30, 2009 compared with $19.7 million for the three months ended September 30, 2008. The Company recorded diluted earnings per share of $0.29 for the three months ended September 30, 2009 compared with $0.31 for the three months ended September 30, 2008.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the three month periods ended September 30, 2009 and 2008 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

(in thousands)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008
Operating Revenues:		
Electric	$ 47	$ 62
Nonelectric	1,214	492
Cost of Goods Sold	1,202	535
Other Nonelectric Expenses	59	19

Electric

(in thousands)	Three Months Ended September 30, 2009	2008	Change	% Change
Retail Sales Revenues	$66,067	$64,539	$ 1,528	2.4
Wholesale Revenues	3,388	9,876	(6,488)	(65.7)
Net Marked-to-Market Gain	956	65	891	
Other Revenues	3,142	8,403	(5,261)	(62.6)
Total Operating Revenues	$73,553	$82,883	$(9,330)	(11.3)
Production Fuel	13,172	18,732	(5,560)	(29.7)
Purchased Power System Use	11,112	10,456	656	6.3
Other Operation and Maintenance Expenses	23,327	33,091	(9,764)	(29.5)
Depreciation and Amortization	9,015	7,864	1,151	14.6
Property Taxes	2,194	2,227	(33)	(1.5)
Operating Income	$14,733	$10,513	$ 4,220	40.1

The main factors contributing to the increase in retail sales revenues are: (1) a $0.8 million increase in North Dakota interim rates, (2) a $0.7 million increase in South Dakota rates, and (3) $0.4 million in accrued revenues related to transmission asset investments subject to recovery in Minnesota under a rate rider, partially offset by a decrease in

revenues related to a 3.7% reduction in retail kilowatt-hour (kwh) sales. Mild summer weather in 2009, which resulted in a 37.5% decrease in cooling-degree days between the quarters, was the main factor contributing to the reduction in retail kwh sales.
On November 4, 2008 Otter Tail Power Company (OTP) filed for a general rate increase of 5.1% or $6.0 million in North Dakota. An interim rate increase of 4.1% or $4.8 million was granted effective January 1, 2009. OTP has entered into a proposed

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settlement agreement which is subject to approval by the North Dakota Public Service Commission. The settlement includes a proposed increase in North Dakota retail electric rates of $3.9 million or approximately 3.3%. Interim rates will remain in effect for all North Dakota customers until final, approved rates go into effect. As of September 30, 2009, OTP had reserved $0.7 million for revenues collected under interim rates in excess of the rate increase agreed to in the proposed settlement, which will be credited to North Dakota customers after final rates have been approved.
Wholesale electric revenues from company-owned generation were $3.2 million for the quarter ended September 30, 2009 compared with $9.1 million for the quarter ended September 30, 2008. A 34.1% decrease in wholesale kwh sales due to reduced plant availability and lower wholesale demand, combined with a 47.5% decrease in revenue per kwh sold due to lower wholesale prices, resulted in the decrease in wholesale electric revenues. Net gains from energy trading activities, including net mark-to-market gains on forward energy contracts, were $1.2 million for the quarter ended September 30, 2009 compared with net gains of $0.8 million for the quarter ended September 30, 2008. Other electric operating revenues decreased $5.3 million as a result of a decrease in revenues from construction work completed for other entities on regional energy projects.
The decrease in fuel costs reflects a 24.9% decrease in kwhs generated from OTP s fossil fuel-fired plants, combined with a 6.4% decrease in the cost of fuel per kwh generated at those plants. The decrease in kwhs generated was related to a reduction in plant availability, partly due to an unplanned outage for generator repairs at Coyote Station. Lower diesel fuel prices in 2009 have resulted in lower costs to transport coal by rail and lower operating costs at the mine that supplies coal to Coyote Station, resulting in lower fuel costs per kwh generated at OTP s coal burning plants. Generation for retail sales decreased 15.0% and generation used for wholesale electric sales decreased 34.1% between the quarters.
The increase in purchased power system use was due to a 78.1% increase in kwhs purchased to make up for the reduction in the availability of company-owned generation. Despite the 78.1% increase in kwh purchases to serve retail customers, purchased power costs increased by only 6.3% as a result of a 40.3% decrease in the cost per kwh purchased. Decreases in natural gas prices, increased output from regional hydroelectric plants, increased efficiency in wholesale electric markets and a decline in industrial demand for electricity are factors that have contributed to a significant decline in wholesale electric prices in 2009.
The decrease in other electric operating and maintenance expenses reflects the following: (1) a $4.5 million decrease in costs associated with construction work completed for other entities on regional energy projects, commensurate with a $5.3 million decrease in related revenue, (2) recognition, in the third quarter of 2008, of $1.5 million in costs eligible for recovery through the Minnesota Resource Recovery Rider that had been deferred pending approval of the rider, (3) a $1.2 million reduction in external services expenses for power-plant maintenance and tree trimming, (4) a $1.0 million reduction in employee incentive expenses, (5) a $0.5 million reduction in travel expenses related to decreased fuel costs and decreased vehicle usage for operations and reductions in employee training expenses, and (6) a $0.5 million decrease in material and operating supply expenses mainly related to boiler maintenance expenses incurred in the third quarter of 2008. The increase in depreciation expense mainly is due to the addition of 32 wind turbines at the Ashtabula Wind Energy Center to utility plant in service at the end of 2008.

Plastics

	Three Months Ended September 30,			%
(in thousands)	2009	2008	Change	Change
Operating Revenues	$27,353	$36,690	$(9,337)	(25.4)
Cost of Goods Sold	23,066	32,189	(9,123)	(28.3)
Operating Expenses	1,248	672	576	85.7
Depreciation and Amortization	667	733	(66)	(9.0)
Operating Income	$ 2,372	$ 3,096	$ (724)	(23.4)

Operating revenues and operating income for the plastics segment decreased as result of a 28.3% decrease in the price per pound of pipe sold partially offset by a 4.0% increase in pounds sold. Beginning in 2008, significant reductions in new home construction in markets served by the plastic pipe companies have resulted in reduced demand and lower prices for polyvinyl chloride (PVC) pipe products. Costs per pound of pipe sold decreased 31.1% between the quarters. The increase in operating expenses reflects a $0.8 million reduction in multi-year accrued bonus incentives in the third quarter of 2008 related to a significant decrease in plastics segment pipe sales and profits in 2008.

Manufacturing

(in thousands)	Three Months Ended September 30, 2009	2008	Change	% Change
Operating Revenues	$75,928	$127,778	$(51,850)	(40.6)
Cost of Goods Sold	60,339	105,965	(45,626)	(43.1)
Operating Expenses	8,071	12,725	(4,654)	(36.6)
Plant Closure Costs		883	(883)	
Depreciation and Amortization	5,778	5,146	632	12.3
Operating Income	$ 1,740	$ 3,059	$ (1,319)	(43.1)

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

Revenues at DMI Industries, Inc. (DMI) decreased $28.6 million as a result of lower volumes of wind towers being sold related to the 2009 slowdown of installed megawatts of wind energy.

Revenues at BTD Manufacturing, Inc. (BTD) decreased $14.5 million as a result of decreases of $10.3 million from reduced sales volume, $3.2 million from lower prices and $1.0 million from scrap sales due to lower steel prices and less scrap.

Revenues at ShoreMaster, Inc. (ShoreMaster) decreased $6.6 million. The decrease mainly reflects revenues recognized on a commercial construction project in the third quarter of 2008 along with a reduction in sales of residential products between the quarters.

Revenues at T.O. Plastics, Inc. (T.O. Plastics) decreased $2.1 million due to a decline in sales volumes.

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

Cost of goods sold at DMI decreased $28.3 million as a result of reductions in production and sales of wind towers. Also, cost of goods sold in the third quarter of 2008 included $1.5 million in costs associated with start-up inefficiencies at DMI s Oklahoma plant.

Cost of goods sold at BTD decreased $9.1 million as a result of reduced sales volume.

Cost of goods sold at ShoreMaster decreased $6.7 million mainly related to costs incurred on a commercial construction project in the third quarter of 2008 but also due to a decrease in sales of residential products.

Cost of goods sold at T.O. Plastics decreased $1.6 million as a result of a decrease in volume of products sold.

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

Operating expenses at DMI decreased $1.8 million, reflecting decreases in most expense categories as a result of initiatives taken to reduce expenses in response to the recent economic downturn.

Operating expenses at BTD decreased $1.4 million mostly due to a reduction in incentive compensation directly related to decreased sales, but also reflecting a $0.2 million decrease in expenses for outsourced services.

Operating expenses at ShoreMaster decreased $1.2 million, excluding the $0.9 million in plant closure costs incurred in the third quarter of 2008, mainly as a result of reductions in payroll costs related to termination costs incurred in the third quarter of 2008, professional services and insurance expense.

Operating expenses at T.O. Plastics decreased by less than $0.2 million between the quarters.
The $0.9 million in plant closure costs in the third quarter of 2008 includes employee-related termination obligations, asset impairment costs and a reserve for additional expenses incurred related to the closing of ShoreMaster s production facility in California following the completion of a major marina project in the state in 2008.
Depreciation expense increased as a result of capital additions at DMI and BTD in 2008.

Health Services

(in thousands)	Three Months Ended September 30, 2009	2008	Change	% Change
Operating Revenues	$27,053	$31,139	$(4,086)	(13.1)
Cost of Goods Sold	22,260	24,779	(2,519)	(10.2)
Operating Expenses	4,841	4,726	115	2.4
Depreciation and Amortization	972	1,020	(48)	(4.7)
Operating (Loss) Income	$ (1,020)	$ 614	$(1,634)	(266.1)

Revenues from scanning and other related services were down $2.9 million and revenues from equipment sales and servicing decreased $1.2 million for the three months ended September 30, 2009 compared with the three months ended September 30, 2008. The decrease in cost of goods sold was directly related to the decreases in sales revenue, but was negatively impacted by higher-than-expected service and maintenance costs. The increase in operating expenses reflects a $0.6 million gain on the sale of fixed assets in the third quarter of 2008 which more than offset expense reductions in the third quarter of 2009. The imaging side of the business continues to be affected by less than optimal utilization of certain imaging assets.

Food Ingredient Processing

(in thousands)	Three Months Ended September 30, 2009	2008	Change	% Change
Operating Revenues	$18,691	$15,333	$ 3,358	21.9
Cost of Goods Sold	13,432	15,380	(1,948)	(12.7)
Operating Expenses	993	540	453	83.9
Depreciation and Amortization	1,205	1,057	148	14.0
Operating Income (Loss)	$ 3,061	$ (1,644)	$ 4,705	286.2

The increase in food ingredient processing revenues is due to a 16.3% increase in the price per pound of product sold, combined with a 4.8% increase in pounds of product sold. Conversely, cost of goods sold decreased as a result of a 16.7% decrease in the cost per pound of product sold as increased production and sales have decreased overhead absorption costs per pound of product produced and sold and raw material and energy costs were higher in the third quarter of 2008.

Other Business Operations

(in thousands)	Three Months Ended September 30, 2009	2008	Change	% Change
Operating Revenues	$36,123	$59,650	$(23,527)	(39.4)
Cost of Goods Sold	23,423	36,221	(12,798)	(35.3)
Operating Expenses	12,307	15,194	(2,887)	(19.0)
Depreciation and Amortization	616	609	7	1.1

Operating (Loss) Income	$ (223)	$ 7,626	$ (7,849)	(102.9)

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

Revenues at Foley Company decreased $10.3 million due to a decrease in volume of jobs in progress related to the recent economic recession and increased competition for available work.

Revenues at Aevenia, Inc. (Aevenia) decreased $9.2 million as a result of a decrease in jobs in progress, especially wind-energy projects, related to the recent economic recession and tight credit.

Revenues at E.W. Wylie Corporation (Wylie) decreased $4.0 million as a result of the effect of lower diesel fuel prices being passed through to customers and a 9.2% reduction in miles driven by company-owned trucks directly related to the recent economic recession. Also, increased competition for fewer loads has driven down shipping rates.

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

Cost of goods sold at Foley Company decreased $8.3 million as a result of decreases in construction activity and jobs in progress.

Cost of goods sold at Aevenia decreased $4.5 million as a result of a reduction of jobs in progress.

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

Operating expenses at Wylie decreased $2.3 million between the quarters. Fuel costs decreased $2.5 million as a result of a 41.8% decrease in fuel costs per gallon combined with the 9.2% decrease in miles driven by company-owned trucks. Subcontractor expenses decreased $0.5 million as a result of the decrease in fuel costs per gallon. The decreases in fuel costs were partially offset by an increase in equipment repair expenses of $0.5 million and an increase in rent expenses of $0.2 million, mainly related to additional equipment leases.

Operating expenses at Aevenia decreased $0.5 million between the quarters as a result of reductions in incentives directly related to less profitability between the quarters.

Corporate

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

	Three Months Ended September 30,			%
(in thousands)	2009	2008	Change	Change
Operating Expenses	$3,075	$3,384	$(309)	(9.1)
Depreciation and Amortization	92	134	(42)	(31.3)

The decrease in corporate operating expenses reflects reductions in insurance costs.

Interest Charges

Interest charges increased $0.1 million in the third quarter of 2009 compared with the third quarter of 2008 as a result of the issuance of a $75 million term loan in May 2009 to finance a portion of the Luverne Wind Farm construction costs. Most of the increase in interest costs related to this debt issuance was offset by a decrease in short-term debt interest due to decreases in short-term debt interest rates and average short-term debt outstanding between the quarters.

Other Income

Other income increased $0.5 million in the third quarter of 2009 compared with the third quarter of 2008 mainly as a result of an increase in allowance for funds used during construction (AFUDC) at OTP.

Income Taxes

The $2.8 million decrease in income taxes between the quarters is partly the result of a $1.9 million (13.8%) decrease in income before income taxes for the three months ended September 30, 2009 compared with the three months ended September 30, 2008. The effective tax rate for the three months ended September 30, 2009 was lower than the effective tax rate for the three months ended September 30, 2008. The reduction from the federal statutory rate mainly reflects the benefit of federal production tax credits and North Dakota wind energy credits related to OTP s wind projects of approximately $1.6 million in the third quarter of 2009 compared with $0.7 million in the third quarter of 2008. Federal production tax credits 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, 2009 and 2008

Consolidated operating revenues were $781.5 million for the nine months ended September 30, 2009 compared with $976.8 million for the nine months ended September 30, 2008. Operating income was $32.3 million for the nine months ended September 30, 2009 compared with $47.1 million for the nine months ended September 30, 2008. The Company recorded diluted earnings per share of $0.48 for the nine months ended September 30, 2009 compared with $0.69 for the nine months ended September 30, 2008.

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, 2009 and 2008 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

(in thousands)	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Operating Revenues:		
Electric	$ 162	$ 235
Nonelectric	3,300	1,676
Cost of Goods Sold	3,228	1,600
Other Nonelectric Expenses	234	311

Electric

(in thousands)	Nine Months Ended September 30, 2009	2008	Change	% Change
Retail Sales Revenues	$206,395	$209,228	$ (2,833)	(1.4)
Wholesale Revenues	11,423	19,681	(8,258)	(42.0)
Net Marked-to-Market Gain	2,130	2,284	(154)	(6.7)
Other Revenues	12,809	17,946	(5,137)	(28.6)
Total Operating Revenues	$232,757	$249,139	$(16,382)	(6.6)
Production Fuel	43,585	53,444	(9,859)	(18.4)
Purchased Power System Use	40,362	39,598	764	1.9
Other Operation and Maintenance Expenses	79,216	87,591	(8,375)	(9.6)
Depreciation and Amortization	27,001	23,378	3,623	15.5
Property Taxes	6,939	7,414	(475)	(6.4)
Operating Income	$ 35,654	$ 37,714	$ (2,060)	(5.5)

The main reason for the decline in retail sales revenue was a $10.5 million decrease in fuel cost recovery revenues mainly related to a decrease in costs per kwh for fuel and purchased power between the periods and a $0.5 million increase in a Minnesota interim rate refund payable in the first quarter of 2009. These revenue decreases were partially offset by: (1) a $5.5 million increase in Minnesota and North Dakota resource recovery rider revenues, (2) $2.9 million in revenues related to a North Dakota effective interim rate increase of 3.3% in 2009 (reduced from 4.1% in June 2009), and (3) $0.8 million from a general rate increase in South Dakota that went into effect in May 2009.

Wholesale electric revenues from sales from company-owned generation were $10.2 million for the nine months ended September 30, 2009 compared with $18.2 million for the nine months ended September 30, 2008 as a result of a

39.7% decrease in the average price per kwh sold, combined with a 7.3% decrease in wholesale kwh sales. Fuel costs related to wholesale sales decreased $2.4 million between the quarters as a result of the decrease in wholesale kwh sales combined with reductions in fuel costs and generation at OTP s combustion turbine peaking plants. Reductions in industrial consumption of electricity, declining natural gas prices, increased efficiency in wholesale electric markets and increased generation from renewable wind and hydroelectric resources have driven down prices for electricity in the wholesale market. Net gains from energy trading activities, including net mark-to-market gains on forward energy contracts, were $3.4 million for the nine months

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ended September 30, 2009 compared with $3.8 million for the nine months ended September 30, 2008 as a result of a reduction in margins on energy trades between the periods. Other electric operating revenues decreased $4.5 million as a result of a decrease in revenues from construction and permitting work completed for other entities on regional energy projects and $0.6 million due to a decrease in transmission service related revenues.

The decrease in fuel costs reflects an 18.2% decrease in kwhs generated from OTP s fossil fuel-fired plants. Fuel costs were also reduced as a result of wind turbines owned by OTP providing 9.9% of total kwh generation in the first nine months of 2009 compared with 3.2% in the first nine months of 2008. Generation for retail sales decreased 12.5% while generation used for wholesale electric sales decreased 7.3% between the periods.

The increase in purchased power system use is due to a 68.8% increase in kwhs purchased, mostly offset by a 39.6% reduction in the cost per kwh purchased. The increase in kwh purchases for system use is related to a reduction in the availability of company-owned generation resulting from maintenance outages at Big Stone and Hoot Lake Plants, a six-week scheduled maintenance shutdown of Coyote Station in the second quarter of 2009 and an unplanned outage for generator repairs at Coyote Station in the third quarter of 2009. The decrease in the cost per kwh of purchased power reflects a significant decrease in fuel and purchased power costs across the Mid-Continent Area Power Pool region as a result of recent reductions in industrial consumption of electricity related to the recent economic recession, declining natural gas prices and the availability of increased generation from renewable wind and hydroelectric sources.

The decrease in other electric operating and maintenance expenses reflects the following: (1) a $3.2 million decrease in costs associated with contract work performed for outside entities, (2) $2.0 million for turbine repairs and boiler maintenance at Hoot Lake Plant in 2008, (3) a $0.9 million reduction in travel expenditures related to a 39.3% decrease in fuel prices and decreased vehicle usage for operations, (4) a $0.8 million reduction in tree-trimming expenditures, (5) a $0.5 million decrease in employee expenses related to the purchase of new fire-retardant clothing in 2008 and reductions in management education and training expenses in 2009, (6) a $0.3 million decrease in expenses for computer and network services mainly related to reductions in software license costs, (7) a $0.3 million decrease in reagent (ash treatment) expenses at Coyote Station due to a 23.9% reduction in kwh generation between the periods related to a six-week scheduled maintenance shutdown in 2009, and (8) a $0.2 million reduction in conservation incentive payments to customers for thermal storage installations.

The increase in depreciation expense mainly is due to the addition of 32 wind turbines at the Ashtabula Wind Energy Center to utility plant in service at the end of 2008. The decrease in property taxes is related to reductions in valuations of utility property in Minnesota and on the Big Stone Plant in South Dakota.

Plastics

	Nine Months Ended September 30,			%
(in thousands)	2009	2008	Change	Change
Operating Revenues	$63,066	$99,685	$(36,619)	(36.7)
Cost of Goods Sold	58,097	87,810	(29,713)	(33.8)
Operating Expenses	3,759	3,939	(180)	(4.6)
Depreciation and Amortization	2,100	2,251	(151)	(6.7)
Operating (Loss) Income	$ (890)	$ 5,685	$ (6,575)	(115.7)

Operating revenues and operating income for the plastics segment decreased as result of a 13.4% decrease in pounds of pipe sold. A 25.4% decrease in PVC pipe prices also contributed to the decrease in operating revenues. The decrease in costs of goods sold was due to the decrease in pounds of pipe sold and a 22.1% decrease in costs per pound of PVC pipe sold. The decrease in operating expenses is due to reductions in selling expenses. Significant reductions in new home construction in markets served by the plastic pipe companies have resulted in reduced demand and lower prices for PVC pipe products.

Manufacturing

(in thousands)	Nine Months Ended September 30, 2009	2008	Change	% Change
Operating Revenues	$248,790	$345,715	$(96,925)	(28.0)
Cost of Goods Sold	199,782	288,190	(88,408)	(30.7)
Operating Expenses	28,481	33,261	(4,780)	(14.4)
Product Recall and Testing Costs	1,766		1,766	
Plant Closure Costs		2,295	(2,295)	
Depreciation and Amortization	16,802	13,771	3,031	22.0
Operating Income	$ 1,959	$ 8,198	$ (6,239)	(76.1)

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

Revenues at DMI decreased $52.2 million due to a decrease in volume of towers produced, mainly as a result of delays or suspension of orders related to the economic recession and wind developers limited access to financing.

Revenues at BTD decreased $18.3 million as a result of decreases of $13.6 million from reduced sales volume, $3.2 million from lower prices and $2.6 million in scrap sales revenue related to lower steel prices and less scrap, partially offset by a $1.1 million increase in revenues from Miller Welding & Iron Works, Inc. (Miller Welding), acquired in May 2008.

Revenues at ShoreMaster decreased $17.9 million due to decreases in both residential and commercial sales related to the recent economic recession and credit restraints affecting dealers and consumers.

Revenues at T.O. Plastics decreased $8.5 million due to a decrease in volume of products sold as customers utilized existing inventory in the channel.

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

Cost of goods sold at DMI decreased $57.8 million as a result of reductions in production and sales of wind towers related to current economic conditions. Also, cost of goods sold in the first nine months of 2008 included $4.3 million in costs associated with start-up inefficiencies at DMI s Oklahoma plant and $3.2 million in additional labor and material costs on a production contract at the Fort Erie plant.

Cost of goods sold at BTD decreased $9.3 million. A decrease of $10.2 million in cost of goods sold related to a decrease in sales volume and $3.2 million in lower prices for raw material was partially offset by a $1.4 million increase in costs of goods sold at Miller Welding, acquired in May 2008 and $2.7 million in unabsorbed overhead costs due to the lower volume of products produced and sold.

Cost of goods sold at ShoreMaster decreased $14.1 million mainly due to a decrease in sales of residential and commercial products partially offset by $1.8 million in additional costs recorded on a marina construction project.

Cost of goods sold at T.O. Plastics decreased $7.2 million mainly as a result of a decrease in volume of products sold.

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

Operating expenses at DMI decreased $1.7 million, reflecting decreases in most expense categories as a result of initiatives taken to reduce expenses in response to the recent economic downturn.

Operating expenses at BTD decreased $1.5 million mostly due to a reduction in incentive compensation directly related to decreased sales.

Operating expenses at ShoreMaster decreased $1.4 million, excluding the $2.3 million in plant closure costs incurred in 2008 and the $1.8 million in product recall and testing costs incurred in 2009, mainly as a result of reductions in payroll costs and selling expenses.

Operating expenses at T.O. Plastics decreased by $0.2 million between the periods mainly in sales-related expenses.

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The $1.8 million in product recall and testing costs in 2009 includes the recognition of $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 and phthalate content at ShoreMaster.

The $2.3 million in plant closure costs in 2008 includes employee-related termination obligations, asset impairment costs and other losses and expenses incurred related to the shutdown and sale of ShoreMaster s production facility in California following the completion of a major marina project in the state.

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

Health Services

(in thousands)	Nine Months Ended September 30, 2009	2008	Change	% Change
Operating Revenues	$83,412	$91,144	$(7,732)	(8.5)
Cost of Goods Sold	66,828	72,198	(5,370)	(7.4)
Operating Expenses	14,801	16,185	(1,384)	(8.6)
Depreciation and Amortization	2,934	3,015	(81)	(2.7)
Operating (Loss)	$ (1,151)	$ (254)	$ (897)	(353.1)

Revenues from scanning and other related services were down $5.5 million and revenues from equipment sales and servicing decreased $2.2 million for the nine months ended September 30, 2009 compared with the nine months ended September 30, 2008. The decrease in cost of goods sold was directly related to the decreases in sales revenue, but was negatively impacted by higher-than-expected service and maintenance costs in the third quarter of 2009. The decrease in operating expenses is the result of measures taken to control and reduce operating expenses. Also, operating expenses in the first half of 2008 are net of a $0.4 million gain on the sale of fixed assets. The imaging side of the business continues to be affected by less than optimal utilization of certain imaging assets.

Food Ingredient Processing

(in thousands)	Nine Months Ended September 30, 2009	2008	Change	% Change
Operating Revenues	$59,358	$47,144	$12,214	25.9
Cost of Goods Sold	44,195	40,416	3,779	9.4
Operating Expenses	2,592	2,181	411	18.8
Depreciation and Amortization	3,313	3,201	112	3.5
Operating Income	$ 9,258	$ 1,346	$ 7,912	587.8

The increase in food ingredient processing revenues is due to an 8.4% increase in pounds of product sold, combined with a 16.1% increase in the price per pound of product sold. Cost of goods sold increased as a result of the increase in sales volume. The cost per pound of product sold increased only 0.8% between the periods as increased production and sales have decreased overhead absorption costs per pound of product produced and sold and raw material and energy costs were higher in 2008.

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Other Business Operations

(in thousands)	Nine Months Ended September 30, 2009	2008	Change	% Change
Operating Revenues	$97,615	$145,840	$(48,225)	(33.1)
Cost of Goods Sold	63,924	96,443	(32,519)	(33.7)
Operating Expenses	34,745	41,260	(6,515)	(15.8)
Depreciation and Amortization	1,826	1,567	259	16.5
Operating (Loss) Income	$ (2,880)	$ 6,570	$ (9,450)	(143.8)

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

Revenues at Foley Company decreased $21.3 million due to a decrease in volume of jobs in progress related to the recent economic recession and increased competition for available work.

Revenues at Aevenia decreased $18.0 million as a result of a decrease in jobs in progress, especially wind-energy projects, related to the recent economic recession and tight credit.

Revenues at Wylie decreased $8.9 million as a result of the effect of lower diesel fuel prices being passed through to customers combined with an 18.6% reduction in miles driven by company-owned trucks directly related to the recent economic recession. Also, increased competition for fewer loads has driven down shipping rates.

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

Cost of goods sold at Foley Company decreased $19.8 million as a result of decreases in construction activity and jobs in progress.

Cost of goods sold at Aevenia decreased $12.6 million as a result of a reduction of jobs in progress.

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

Operating expenses at Wylie decreased $5.6 million between the periods. Fuel costs decreased $5.9 million as a result of a 45.1% decrease in fuel costs per gallon combined with the 18.6% decrease in miles driven by company-owned trucks. Subcontractor expenses decreased $1.6 million as a result of the decrease in fuel costs per gallon. The decreases in fuel costs were partially offset by an increase in repair and maintenance expenses of $1.1 million and an increase in rent expenses of $0.8 million, mainly related to additional equipment leases.

Operating expenses at Aevenia decreased $0.7 million between the periods as a result of reductions in bonus incentives and other contracted services related to less work volume.

Operating expenses at Foley decreased $0.2 million between the periods.

Corporate

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

	Nine Months Ended September 30,			%
(in thousands)	2009	2008	Change	Change
Operating Expenses	$9,376	$11,696	$(2,320)	(19.8)
Depreciation and Amortization	289	417	(128)	(30.7)

The decrease in corporate operating expenses reflects reductions for salaries and benefits, including health care expenses, and insurance costs.

Interest Charges

Interest charges decreased $0.7 million in the first nine months of 2009 compared with the first nine months of 2008 as a result of decreases in short-term debt interest rates and average short-term debt outstanding between the periods.

Other Income

Other income increased $0.9 million in the first nine months of 2009 compared with the first nine months of 2008 as a result of an increase in AFUDC at OTP.

Income Taxes

The $9.6 million decrease in income taxes between the periods is primarily the result of a $13.2 million decrease in income before income taxes for the nine months ended September 30, 2009 compared with the nine months ended September 30, 2008. The effective tax rate for the nine months ended September 30, 2009 was lower than the effective tax rate for the nine months ended September 30, 2008. The reduction from the federal statutory rate mainly reflects the benefit of federal production tax credits and North Dakota wind energy credits related to OTP s wind projects of approximately $5.5 million in the first nine months of 2009 compared with $2.1 million in the first nine months of 2008. Federal production tax credits 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.

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2009 EXPECTATIONS

The statements in this section are based on our current outlook for 2009 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 expect our 2009 earnings to be near the low end of our previously announced range of $0.70 to $1.10. The earnings guidance is subject to risks and uncertainties given current global economic conditions and the other risk factors outlined below.

Contributing to our earnings guidance for 2009 are the following items:

- We now expect 2009 earnings from our electric segment to be lower than 2008 electric segment earnings. Our expectations for earnings from our electric segment have been revised downward due to the negative impact of milder weather conditions in the third quarter, softness in demand from commercial and industrial customers and lower volumes and margins from wholesale energy sales. Declining demand along with the lowest natural gas prices in years are having a dramatic impact on the volume and price that can be realized from sales of excess generation into the marketplace. While 2009 earnings are expected to be impacted by lower than requested electric revenue increases in North Dakota and South Dakota and lower volumes and margins from wholesale energy sales, OTP has benefited from continued cost reduction efforts and higher than expected earnings from the allowance for funds used during construction related to construction of its Luverne Wind Farm.

- We expect our plastics segment s 2009 performance to be below 2008 earnings, given continued poor economic conditions.

- We now expect our manufacturing segment to post a net loss in 2009 as a result of the following:
  - BTD continued to experience unexpected declines in customer demand in the third quarter of 2009 and expects soft demand to continue for the rest of the year resulting in lower earnings compared with 2008.

  - While spending on waterfront products is expected to decline in the current economy, a reduction in net loss compared with 2008 is expected at ShoreMaster given the restructuring that has occurred in its business. ShoreMaster has implemented significant cost reductions across the organization, reduced capital spending and reorganized its business units for more efficient operations. ShoreMaster continues to experience performance issues on a large commercial construction project which is having a negative effect on its results of operations.

  - DMI s earnings in 2009 are now expected to be in line with its 2008 earnings, despite the sluggish economy, as a result of expense reductions and productivity improvements.

  - T. O. Plastics expects slightly lower earnings in 2009 compared with 2008. While T.O. Plastics expects economic challenges to continue, it has implemented cost reductions and efficiency projects to maintain profitability.

  - Backlog in place in the manufacturing segment to support revenues for the remainder of 2009 is approximately $61 million compared with $131 million one year ago.

- We now expect our health services segment to record a net loss in 2009. Cost reductions implemented in 2009 have not been enough to offset the impact of low utilization of the current fleet of imaging assets. The health services segment leases its imaging assets. These leases expire at various dates from 2010 through 2014.

- We expect increased net income from our food ingredient processing business in 2009 based on expectations of higher sales volumes, lower energy costs and higher production levels in 2009 compared with 2008.

We expect our other business operations segment to have lower earnings in 2009 compared with 2008. The decline in construction projects in 2009 due to poor economic conditions has negatively affected our construction companies. Our trucking operations continue to be impacted by lower selling prices and volumes in its heavy haul business. Backlog in place for our construction businesses is $25 million for the remainder of 2009 compared with $48 million one year ago.

We expect corporate general and administrative costs to decrease in 2009.

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FINANCIAL POSITION

The following table presents the status of our lines of credit as of October 31, 2009 and December 31, 2008:

(in thousands)	Line Limit	In Use on October 31, 2009	Restricted due to Outstanding Letters of Credit	Available on October 31, 2009	Available on December 31, 2008
Otter Tail Corporation Credit Agreement	$200,000	$ 110,000	$ 14,245	$ 75,755	$ 77,706
OTP Credit Agreement	170,000	8,000	250	161,750	142,935
Total	$370,000	$ 118,000	$ 14,495	$ 237,505	$ 220,641

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if current market conditions continue. Despite the recent economic recession, our balance sheet is strong and we are in compliance with our debt covenants. On October 27, 2009 OTP received grant proceeds of approximately $30.2 million from the U.S. Department of Treasury under the American Recovery and Reinvestment Act of 2009 related to its $100.6 million investment in its Luverne Wind Farm. Our dividend payout ratio for the year ended December 31, 2008 was 109% compared to 66% and 68% for the years ended December 31, 2007 and 2006, respectively. Our current indicated annual dividend would result in a dividend per share of $1.19 in 2009. 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 that our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of solid 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. 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 and/or debt securities described in the shelf registration statement. Equity or debt financing will be required in the period 2009 through 2013 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. Also, 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.

Prior to the Company s holding company reorganization on July 1, 2009, the Company s wholly owned subsidiary, Varistar Corporation (Varistar), was the borrower under a $200 million credit agreement (the Credit Agreement) with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. Effective July 1, 2009 all of Varistar s rights and obligations under the Credit Agreement were assigned to and assumed by Otter Tail Corporation.

Beginning July 1, 2009 borrowings bear interest at LIBOR plus 2.375%, subject to adjustment based on the senior unsecured credit ratings of the Company. The Credit Agreement expires October 2, 2010 and is an unsecured revolving credit facility. 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 borrower 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 borrower under the Credit Agreement can reduce the amount available for borrowing under the line by up to $30 million. The Credit Agreement has an accordion feature whereby the line can be increased to $300 million as described in the Credit Agreement.

Prior to the Company s holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now OTP) was the borrower under a $170 million credit agreement (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 Otter Tail Corporation, dba Otter Tail Power Company (now 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 is subject to renewal on July 30, 2011. Following the Company s holding company reorganization, the OTP Credit Agreement is an obligation of OTP.
Prior to the Company s holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now OTP) was the borrower under a $75 million term loan agreement (the OTP Loan Agreement). The OTP Loan Agreement was entered into between Otter Tail Corporation, d/b/a Otter Tail Power Company (now OTP) and JPMorgan Chase Bank, N.A., as Administrative Agent, KeyBank National Association, as Syndication Agent, Union Bank, N.A., as Documentation Agent, and the Banks named therein. The OTP Loan Agreement provides for a $75 million term loan due May 20, 2011, which OTP is using to support the working capital needs and other capital requirements of its electric operations, including construction of the Luverne Wind Farm in North Dakota. Borrowings under the OTP Loan Agreement currently bear interest at a rate equal to the base rate in effect from time to time. The base rate is a fluctuating rate per annum equal to (i) the highest of (A) JPMorgan Chase Bank, N.A. s prime rate, (B) the Federal funds effective rate plus 0.5% per annum, and (C) a daily LIBOR rate plus 1.0% per annum, plus (ii) a margin of 1.5% to 3.0% determined on the basis of OTP s senior unsecured credit ratings, as provided in the OTP Loan Agreement. At OTP s option, the interest rate on outstanding borrowings may be converted to a LIBOR rate that would fluctuate based on the rate at which deposits of U.S. dollars in the London interbank market are quoted, plus a margin of 2.5% to 4.0% determined on the basis of OTP s senior unsecured credit ratings, as provided in the OTP Loan Agreement. The interest rate on borrowings under the OTP Loan Agreement was 3.79% at September 30, 2009. The OTP Loan Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make certain investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Following the Company s holding company reorganization, the OTP Loan Agreement is an obligation of OTP.
The note purchase agreement relating to the $90 million 6.63% senior notes due December 1, 2011 entered into in December 2001 by Otter Tail Corporation (now known as OTP), as amended (the 2001 Note Purchase Agreement), the note purchase agreement relating to the $50 million 5.778% senior note due November 30, 2017 entered into in February 2007 by Otter Tail Corporation (now known as OTP) and assigned to the Company (formerly known as Otter Tail Holding Company), as amended (the Cascade Note Purchase Agreement), and the note purchase agreement relating to our $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, entered into in August 2007 by Otter Tail Corporation (now known as OTP), 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. Prior to the effectiveness of the holding company reorganization, the Company s obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement were guaranteed by Varistar and certain of its material subsidiaries. Following the effectiveness of the holding company reorganization, only the obligations of the Company under the Cascade Note Purchase Agreement remain guaranteed by Varistar and certain of its material subsidiaries (and not by OTP).

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Financial Covenants

As of September 30, 2009 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.

Following the Company s holding company reorganization on July 1, 2009: (1) the Varistar Credit Agreement is an obligation of the Company, as assignee of Varistar, guaranteed by Varistar and its material subsidiaries, (2) the Cascade Note Purchase Agreement is an obligation of the Company, as assignee of Otter Tail Corporation (now OTP) prior to the reorganization, guaranteed by Varistar and its material subsidiaries, and (3) the OTP Credit Agreement, the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement are obligations of OTP.

Following the Company s holding company reorganization on July 1, 2009 the Company s borrowing agreements are subject to certain financial covenants. Specifically:

Under the credit agreement relating to the $200 million credit facility of the Company (as assignee of Varistar Corporation), the Company 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 (each measured on a consolidated basis), as provided in the credit agreement.

Under the Cascade Note Purchase Agreement, the Company may not permit its Consolidated Debt to exceed 60% of Consolidated Total Capitalization or its Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the Debt of OTP to exceed 60% of OTP s Total Capitalization, or permit the Priority Debt of Varistar and its subsidiaries to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement.

Under the Loan Agreement and the credit agreement relating to OTP s $170 million credit facility, 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 Loan Agreement.

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

Our ratings at October 31, 2009 were:

Otter Tail Corporation	Moody s Investors Service	Fitch Ratings	Standard & Poor s
Corporate Credit/Long-Term Issuer Default Rating	Baa3	BBB-	BBB-
Senior Unsecured Debt	Baa3	BBB-	BB+
Outlook	Stable	Stable	Stable

Otter Tail Power Company	Moody s Investors Service		Standard

		Fitch Ratings	& Poor s
Corporate Credit/Long-Term Issuer Default Rating	A3	BBB	BBB-
Senior Unsecured Debt	A3	BBB+	BBB-
Outlook	Stable	Stable	Stable

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

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DMI has a $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement expires in March 2011. Accounts receivable totaling $114.5 million were sold in the first nine months of 2009. Discounts, fees and commissions of $304,000 for the nine months ended September 30, 2009 were charged to operating expenses in the consolidated statements of income. The balance of receivables sold that was outstanding to the buyer as of September 30, 2009 was $25.5 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.

In December 2007, ShoreMaster entered into an agreement with GE Commercial Distribution Finance Corporation (CDF) to provide floor plan financing for certain dealer purchases of ShoreMaster products. Financings under this agreement began in 2008. As part of its marketing programs, ShoreMaster pays floor plan financing costs of its dealers for CDF financed purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer s order. CDF exercised its right under this agreement to terminate the agreement effective February 28, 2009. The termination of the agreement has no effect on ShoreMaster s obligations to CDF for any products financed, advances made or approvals granted by CDF under the agreement prior to the effective termination date. Additionally, ShoreMaster is liable for expenses incurred by CDF before or after the effective termination date in connection with the collection of any amounts or other charges as set forth in the agreement. The floor plan financing agreement requires ShoreMaster to repurchase new and unused inventory repossessed by CDF to satisfy the dealer s obligations to CDF under this agreement. ShoreMaster has agreed to unconditionally guarantee to CDF all current and future liabilities which any dealer owes to CDF under this agreement. Any amounts due under this guaranty will be payable despite impairment or unenforceability of CDF s security interest with respect to inventory that may prevent CDF from repossessing the inventory. The aggregate total of amounts owed by dealers to CDF under this agreement was $1.9 million on September 30, 2009. ShoreMaster has incurred no losses under this agreement. We believe current available cash and cash generated from operations provide sufficient funding in the event there is a requirement to perform under this agreement.

Cash provided by operating activities was $140.6 million for the nine months ended September 30, 2009 compared with cash provided by operating activities of $40.2 million for the nine months ended September 30, 2008. The $100.4 million increase in cash from operating activities reflects a $98.2 million increase in cash from working capital items between the periods. Major sources of funds from working capital items in the first nine months of 2009 were a decrease in receivables of $30.0 million, a decrease in other current assets of $29.3 million, a decrease in inventories of $18.7 million and an increase in interest and income taxes payable/receivable of $17.0 million, offset by a decrease in payables and other current liabilities of $32.5 million.

The $30.0 million decrease in accounts receivable reflects decreases in trade receivables of $28.0 million in our manufacturing segment due to declines in production and sales activity related to the recent economic recession and collections of receivables outstanding on December 31, 2008.

The $29.3 million decrease in other current assets includes: (1) a decrease of $22.8 million in costs in excess of billings at DMI as a result of decreased production activity and (2) a $13.5 million decrease in accrued utility revenues related to decreases in unbilled and accrued fuel clause adjustment revenues due to seasonal kwh sales reductions and declining purchased power costs, offset by (3) a $6.1 million increase in prepaid expenses across all companies related to the timing of 2009 annual insurance premiums and other payments and (4) a $0.7 million increase in costs in excess of billings at Aevenia.

The $18.7 million decrease in inventories is due to reductions of $13.0 million at the plastic pipe companies and $5.3 million at BTD related to reductions in production and sales and decreases in PVC resin and steel prices.

The $17.0 million increase in interest and income taxes payable/receivable is mainly related to the receipt of a $26.3 million federal income tax refund in May 2009 related to the application of 2008 tax credits, and losses related to bonus depreciation, to tax liabilities paid in previous years. The receipt of the tax refund was partially offset by recent reductions in income tax expenses combined with the accrual of renewable energy tax credits earned in the first nine months of 2009.

The $32.5 million decrease in payables and other current liabilities includes: (1) an $18.2 million decrease in accounts payable and accrued costs at DMI mainly related to a decrease in production activity, (2) $8.2 million related to the payment of accrued wages and benefits in 2009, (3) a $3.2 million decrease in accounts payable and accrued costs at Idaho Pacific Holdings, Inc. (IPH) related to reductions in potato purchases at the end of the processing year and lower fuel prices and (4) a $3.1 million decrease in accounts payable at Foley Company related to a reduction in construction activity in 2009.

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Net cash used in investing activities was $166.2 million for the nine months ended September 30, 2009 compared with $206.9 million for the nine months ended September 30, 2008. Cash used for capital expenditures decreased by $22.1 million between the periods mainly due to an increase in capital expenditures at OTP for payments in the first nine months of 2008 related to the construction of 27 wind turbines at the Langdon Wind Energy Center. Cash used for capital expenditures of $150.1 million in the first nine months of 2009 includes $124.2 million at OTP, mainly related to the construction of 33 wind turbines at its Luverne Wind Farm, and $9.8 million at DMI, mainly for equipment. We paid $41.7 million in cash to acquire Miller Welding in May 2008. The $20.8 million increase in other investments and long-term assets includes the deposit of $16.3 million in cash in an escrow account to be used for the purchase of wind turbines for OTP s Luverne Wind Farm.

Net cash provided by financing activities was $25.1 million for the nine months ended September 30, 2009 compared with $144.2 million for the nine months ended September 30, 2008. Reductions in short-term borrowings of $12.4 million in the first nine months of 2009 compared to proceeds from short-term borrowings of $17.0 million used to fund a portion of capital expenditures in the first nine months of 2008. We borrowed $75.0 million in May 2009 under a two-year term loan agreement. The proceeds are being used to support the working capital needs and other capital requirements of our electric operations, including construction of the Luverne Wind Farm in North Dakota. We paid $3.7 million in short-term and long-term debt issuance expenses in the first nine months of 2009. We made payments of $6.0 million for the retirement of long-term debt in the first nine months of 2009 compared with $2.7 million in the first nine months of 2008. The $3.3 million increase in payments for the retirement of long-term debt between the periods reflects a $3.5 million payment for the early retirement of our Lombard US Equipment Finance Note in June 2009. We paid $32.2 million in dividends on common and preferred shares in the first nine months of 2009 compared with $27.4 million in the first nine months of 2008. The increase in dividend payments is due to an increase in common shares outstanding between the periods mainly related to our September 2008 common stock offering.

Due to the approval of additional capital expenditures for our electric segment in 2009 related to construction of the Luverne Wind Farm and reductions in capital expenditures related to OTP s withdrawal from participation in Big Stone II, we have revised our estimated capital expenditures for our electric segment for 2009 and the years 2009 through 2013 from those presented on page 27 of our 2008 Annual Report to Shareholders as presented in the following table:

(in millions)	2009	2009-2013
Electric	$145	$684
Plastics	5	18
Manufacturing	13	115
Health Services	3	27
Food Ingredient Processing	3	14
Other Business Operations	2	11
Corporate		1
Total	$171	$870

The following items have increased our contractual obligations from those reported in the table under the caption Capital Requirements on page 27 of our 2008 Annual Report to Shareholders:

our long-term debt obligations have increased by $75.0 million in 2011 as a result of borrowing $75 million under a variable rate term loan agreement in May 2009,

our interest on long-term debt obligations has increased by $1.8 million in 2009, $2.8 million in 2010 and $1.1 million in 2011 related to the $75 million borrowed under a variable rate term loan agreement in May 2009, based on an annual interest rate of 3.79% in effect on September 30, 2009, our coal contracts (required minimums) increased $3.0 million in 2009 and $6.5 million in 2010 related to an agreement entered into in March 2009 for the purchase of coal to cover a portion of current coal requirements at OTP s Big Stone Plant,

our capacity and energy requirements increased by $7.4 million in 2010, $11.8 million in 2011, $12.9 million in 2012 and $4.4 million in 2013 as a result of entering into a three-year capacity and energy purchase agreement in May 2009, and

our purchase obligations increased by $100.6 million in 2009 related to OTP s construction of 33 wind turbines at its Luverne Wind Farm in North Dakota.

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

Critical Accounting Policies Involving Significant Estimates

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

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, valuation of forward energy contracts, unbilled electric revenues, accrued renewable resource and transmission rider revenues, MISO electric market residual load adjustments, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors. A discussion of critical accounting policies is included under the caption Critical Accounting Policies Involving Significant Estimates on pages 34 through 36 of our 2008 Annual Report to Shareholders. There were no material changes in critical accounting policies or estimates during the quarter ended September 30, 2009.

Goodwill Impairment

We believe accounting estimates related to goodwill impairment are critical because the underlying assumptions used for the discounted cash flow can change from period to period and could potentially cause a material impact to the income statement. Additionally, accounting standards requires goodwill be analyzed for impairment on an annual basis using the assumptions that apply at the time the analysis is updated.

The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, future business operating performance, changes in competition or changes in technologies. Management s assumptions about inflation rates and other internal and external economic conditions, such as earnings growth rate, require significant judgment based on fluctuating rates and expected revenues. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects or other assumptions could affect the fair value of one or more business segments, which may result in an impairment charge.

We have approximately $106.8 million of goodwill recorded on our consolidated balance sheet as of September 30, 2009. We have recorded goodwill in each of our business segments, except for our electric utility. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of these businesses, we may be forced to record an impairment charge, which would lead to decreased assets and a reduction in net operating performance. We test goodwill for impairment annually, at December 31, or whenever events or changes in circumstances indicate impairment may have occurred. Goodwill reviews are prepared using estimates of the fair value of our reporting units based on the estimated present value of future discounted cash flows and based on market multiples of EBITDA (earnings before interest, taxes and depreciation).

Accounting standards require a two-step process be performed to analyze whether or not goodwill has been impaired. Step one is to test for potential impairment and requires that the fair value of the reporting unit be compared to its book value including goodwill. If the fair value is higher than the book value, no impairment is recognized. If the fair value is lower than the book value, a second step must be performed. The second step is to measure the amount of impairment loss, if any, and requires that a hypothetical purchase price allocation be done to determine the implied fair value of goodwill. This fair value is then compared to the carrying value of goodwill. If the implied fair value is lower than the carrying value, an impairment must be recorded.

We currently have $12.2 million of goodwill and $4.9 million in nonamortizable trade names recorded on our balance sheet related to the acquisition of ShoreMaster and its subsidiary companies. ShoreMaster produces and markets residential and commercial waterfront equipment, ranging from boatlifts and docks for lakefront property to full commercial marina projects. The business has experienced reduced demand for its products due to the recent economic recession and has incurred net losses.

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We considered these adverse developments in the business to be an indicator of potential impairment of ShoreMaster s goodwill and other intangible assets and, as a result, we tested goodwill for impairment during the current quarter. Based on the current goodwill review, we concluded that no impairment charge was necessary. However, if current economic conditions continue to impact the amount of sales of waterfront products and ShoreMaster is not successful with reorganizing and streamlining its business to improve operating margins according to our projections, the reductions in anticipated cash flows from this business may indicate, in a future period, that its fair value is less than its book value resulting in an impairment of some or all of the goodwill and nonamortizable intangible assets associated with ShoreMaster and a corresponding charge against earnings.

ShoreMaster s current operating plan calls for modest revenue growth in 2010 in line with growth in gross domestic product. With the cost reduction efforts that have occurred over the past year, we expect to breakeven in 2010. Given the nature of ShoreMaster s products and the markets it serves, our operating plans assume revenue and earnings growth begin to occur in 2011. These revenue growth assumptions are consistent with ShoreMaster s historical growth rates before the recent economic downturn. Inherent in these assumptions is that ShoreMaster s manufacturing capacity utilization will increase from current utilization of 40% to approximately 70% of capacity for the year ending 2014. ShoreMaster is expecting its dealer base to grow during this period of time which is reasonable given its historic ability to grow its dealer base. ShoreMaster has not experienced any deterioration in its dealer base during the economic downturn.

The weighted average cost of capital used for this analysis was 13.3% which is reflective of the risks inherent in ShoreMaster s industry. This compares with the previous weighted average cost of capital of 12% which was used in the previous year annual goodwill review for ShoreMaster. We used a terminal value growth rate of 3% in this discounted cash flow analysis.

The current operating plan with its assumptions shows the following:

(in thousands)	
Enterprise Value	$48,600
Interest Bearing Debt	36,500
Market Value of Common Equity	12,100
Book Value of Common Equity	12,000
Excess of Market Value over Book Value	$ 100

The following changes in our assumptions would have the following impact on these estimated values:

Assumption	Change	Impact on Fair Value *(in thousands)*
Annual Revenue Growth Rate	Plus 1%	$ 3,700
Annual Revenue Growth Rate	Minus 1%	(3,600)
Annual Gross Margin	Plus 1%	3,800
Annual Gross Margin	Minus 1%	(3,800)
Discount Rate	Plus .5%	(2,200)
Discount Rate	Minus .5%	2,400

Should the assumptions used in these current operating plans not materialize and the market value of ShoreMaster s common equity is significantly below its book value, an impairment charge of up to $17.1 million could be recorded. An impairment charge of this magnitude would not have a significant impact on the Company s financial position and would not put us in violation of our debt covenants.

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

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Forward Looking Information Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (the Act), we have filed cautionary statements identifying important factors that could cause our actual results to differ materially from those discussed in forward-looking statements made by or on behalf of the Company. When used in this Form 10-Q and in future filings by the Company with the Securities and Exchange Commission, in our press releases and in oral statements, words such as may , will , expect , anticipate , continue , estimate , project , believes or sim are intended to identify forward-looking statements within the meaning of the Act and are included, along with this statement, for purposes of complying with the safe harbor provision of the Act.

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

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

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

- Volatile financial markets and changes in our debt rating could restrict our ability to access capital and could increase borrowing costs and pension plan expenses. Disruptions, uncertainty or volatility in the financial markets can also adversely impact our results of operations, the ability of our customers to finance purchases of goods and services, and our financial condition as well as exert downward pressure on stock prices and/or limit our ability to sustain our current common stock dividend level.

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

- 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.

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

- 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 and could result in poor financial performance.

- Our plans to acquire additional businesses and grow and operate our nonelectric businesses could be limited by state law.

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

- We are subject to risks associated with energy markets.

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

Competition is a factor in all of our businesses.

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

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 many factors, including economic risks and uncertainty associated with proposed federal climate legislation and existing federal environmental regulations, that made proceeding with Big Stone II and committing to $400 million in capital expenditures untenable for OTP customers and our shareholders. As of September

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30, 2009, OTP had incurred $13.6 million in costs related to this project. OTP believes these incurred costs are probable of recovery in future rates and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve OTP s rates. However, 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.

Future operating results of the electric segment will be impacted by the outcome of rate rider filings in Minnesota for transmission investments.

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.

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.

Existing or new laws or regulations addressing climate change or reductions of greenhouse gas emissions by federal or state authorities, such as mandated levels of renewable generation or mandatory reductions in carbon dioxide (CO2) emission levels, taxes on CO2 emissions or cap and trade regimes, that result in increases in electric service costs could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where OTP provides service or through increased market prices for electricity.

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

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.

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

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

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

Technological change in the diagnostic imaging industry could reduce the demand for diagnostic imaging services and require our health services operations to incur significant costs to upgrade their 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 raw materials for processing. Should the supply of these raw materials be affected by poor growing conditions, this could negatively impact the results of operations for this segment.

Our food ingredient processing 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.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

At September 30, 2009 we had exposure to market risk associated with interest rates because we had $108.0 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 2.375% under the Otter Tail Corporation Credit Agreement and $14.5 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 0.5% under the OTP Credit Agreement. At September 30, 2009 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 Idaho Pacific Holdings, Inc. (IPH) are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 14.6% of IPH sales in the first nine months of 2009 were outside the United States and the Canadian operations of IPH pays its operating expenses in Canadian dollars. However, IPH s Canadian subsidiary has locked in exchange rates for the exchange of U.S. dollars (USD) for Canadian dollars (CAD) for approximately 75% of its cash needs for October 2009 and 25% of its cash needs for November and December 2009 by entering into forward foreign currency exchange contracts. On September 30, 2009 IPH s Canadian subsidiary held contracts for the exchange of $1,000,000 USD for $1,120,000 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, 2009 we had $85.4 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, 2009, annualized interest expense and pre-tax earnings would change by approximately $854,000.

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, 2009 OTP had recognized, on a pretax basis, $980,000 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. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. Of the forward energy sales contracts that are marked to market as of September 30, 2009, 100% are 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.

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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, 2009 because the open purchases were not at the same delivery points as the open sales, but these positions were closed by entry into offsetting transactions at those delivery points in October 2009.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and electricity generating capacity on our consolidated balance sheet as of September 30, 2009 and the change in our consolidated balance sheet position from December 31, 2008 to September 30, 2009:

(in thousands)	September 30, 2009
Current Asset Marked-to-Market Gain	$ 6,241
Regulatory Asset Deferred Marked-to-Market Loss	3,616
Current Liability Marked-to-Market Loss	(7,232)
Regulatory Liability Deferred Marked-to-Market Gain	(1,645)
Net Fair Value of Marked-to-Market Energy Contracts	$ 980

(in thousands)	Year-to-Date September 30, 2009
Fair Value at Beginning of Year	$ (123)
Less: Amount Realized on Contracts Entered into in 2008 and Settled in 2009	123
Changes in Fair Value of Contracts Entered into in 2008	
Net Fair Value of Contracts Entered into in 2008 at End of Period	
Changes in Fair Value of Contracts Entered into in 2009	980
Net Fair Value End of Period	$ 980

The $980,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on September 30, 2009 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	4th Quarter 2009	2010	2011	2012	Total
Net Gain	$ 4	$352	$313	$311	$980

We have credit risk associated with the nonperformance or nonpayment by counterparties to our 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. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of

September 30, 2009 was $1,910,000. As of September 30, 2009 we had a net credit risk exposure of $2,602,000 from nine counterparties with investment grade credit ratings and two counterparties that have not been rated by an external credit rating agency but have been evaluated internally and assigned an internal credit rating equivalent to investment grade. We had no exposure at September 30, 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 $2,602,000 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, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

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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.

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 2008. Each monthly contract was for the exchange of $400,000 U.S. dollars for the amount of Canadian dollars stated in each contract. IPH s Canadian subsidiary also entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in July 2009. Each monthly contract was for the exchange of $200,000 U.S. dollars for the amount of Canadian dollars stated in each contract.

The following table lists the contracts outstanding as of September 30, 2009:

(in thousands)	Settlement Period	USD	CAD
Contracts entered into in October 2008	October 2009	$ 400	$ 467
Contracts entered into in July 2009	October 2009 December 2009	600	653
Contracts outstanding on September 30, 2009	October 2009 December 2009	$1,000	$1,120

The following table shows the effect of marking to market IPH s foreign currency exchange forward windows on the Company s consolidated balance sheet as of September 30, 2009 and the change in the Company s consolidated balance sheet position from December 31, 2008 to September 30, 2009:

(in thousands)	Year-to-Date September 30, 2009
Fair Value at Beginning of Year	$ (289)
Less: Amount Realized on Contracts Entered into in 2008 and Settled in 2009	229
Changes in Fair Value of Contracts Entered into in 2008	127
Net Fair Value of Contracts Entered into in 2008 at End of Period	67
Changes in Fair Value of Contracts Entered into in 2009	53
Net Fair Value End of Period	$ 120

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, 2009 were valued and marked to market on September 30, 2009 based on quoted exchange values on September 30, 2009.

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, 2009, 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, 2009.

During the fiscal quarter ended September 30, 2009, 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.

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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 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 Clean Air Act 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 Clean Air Act and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone was and is being operated in compliance with the Clean Air Act 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. The briefing schedule calls for the appellant to submit its brief by mid-October, for appellees to submit their brief by mid-November and for the appellant to submit its reply brief by the end of November. On October 13, 2009, the United States Department of Justice filed a motion seeking a 30-day extension of the time to file an amicus brief in support of the Sierra Club s position. The Court of Appeals granted this motion, as well as the appellees subsequent joint motion with the Sierra Club, extending the time to file the appellees brief and the Sierra Club s reply brief. We anticipate briefing to be complete by the end of January 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 Federal Energy Regulatory Commission (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. The parties are in the process of negotiating a formal settlement agreement to be filed with the FERC.

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

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judgments, where it has assessed that a loss is probable and an amount can be reasonably estimated. The Company believes the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under the caption Risk Factors and Cautionary Statements on pages 29 through 32 of the Company s 2008 Annual Report to Shareholders, which is incorporated by reference to Part I, Item 1A, Risk Factors in the Company s Annual Report on Form 10-K for the year ended December 31, 2008.

Item 6. Exhibits

3.1	Restated Articles of Incorporation of Otter Tail Corporation (incorporated by reference to Exhibit 3.1 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)
3.2	Restated Bylaws of Otter Tail Corporation (incorporated by reference to Exhibit 3.2 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)
4.1	Fourth Amendment dated as of June 30, 2009 to Note Purchase Agreement dated as of December 1, 2001, among Otter Tail Corporation (now known as Otter Tail Power Company) and the noteholders party thereto (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)
4.2	Third Amendment dated as of June 26, 2009 to Note Purchase Agreement dated as of August 20, 2007, among Otter Tail Corporation (now known as Otter Tail Power Company) and each of the holders of notes party thereto (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)
4.3	Amendment No. 2 dated as of June 30, 2009 to Note Purchase Agreement dated as of February 23, 2007, between Otter Tail Corporation (now known as Otter Tail Power Company) and Cascade Investment, L.L.C. (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by Otter Tail Corporation, the predecessor registrant, on July 1, 2009)
4.4	First Supplemental Indenture, dated as of July 1, 2009, between Otter Tail Corporation and U.S. Bank National Association, as Trustee, to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 between Otter Tail Corporation (now known as Otter Tail Power Company) and U.S. Bank National Association (formerly First Trust National Association), as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)
10.1	Standstill Agreement, dated July 1, 2009, by and between Otter Tail Corporation and Cascade Investment, L.L.C. (incorporated by reference to Exhibit 10.1 to the Form 8-K filed by Otter Tail Corporation, the registrant, on July 1, 2009)
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.

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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 9, 2009

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EXHIBIT INDEX

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