Otter Tail Corp
Form 10-Q
November 09, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2012

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 x No o

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

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

Large accelerated filer x Accelerated filer o

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

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

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

October 31, 2012 – 36,166,218 Common Shares ($5 par value)

OTTER TAIL CORPORATION

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# PART I. FINANCIAL INFORMATION

## Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

| (in thousands) | September 30, 2012 | December 31, 2011 |
|---|---|---|
| ASSETS | | |
| Current Assets | | |
| Cash and Cash Equivalents | $-- | $ 14,652 |
| Accounts Receivable: | | |
| Trade—Net | 133,674 | 116,522 |
| Other | 5,488 | 18,807 |
| Inventories | 73,430 | 77,983 |
| Deferred Income Taxes | 12,325 | 12,307 |
| Accrued Utility Revenues | 11,029 | 13,719 |
| Costs and Estimated Earnings in Excess of Billings | 23,900 | 67,109 |
| Regulatory Assets | 21,084 | 27,391 |
| Other | 17,766 | 21,414 |
| Assets of Discontinued Operations | 730 | 29,692 |
| Total Current Assets | 299,426 | 399,596 |
| Investments | 9,920 | 11,093 |
| Other Assets | 26,628 | 26,997 |
| Goodwill | 39,119 | 39,406 |
| Other Intangibles—Net | 14,549 | 15,286 |
| Deferred Debits | | |
| Unamortized Debt Expense | 4,866 | 6,458 |
| Regulatory Assets | 117,537 | 124,137 |
| Total Deferred Debits | 122,403 | 130,595 |
| Plant | | |
| Electric Plant in Service | 1,409,729 | 1,372,534 |
| Nonelectric Operations | 219,537 | 310,320 |
| Construction Work in Progress | 71,017 | 54,439 |
| Total Gross Plant | 1,700,283 | 1,737,293 |
| Less Accumulated Depreciation and Amortization | 642,402 | 659,744 |
| Net Plant | 1,057,881 | 1,077,549 |
| Total Assets | $1,569,926 | $ 1,700,522 |

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

| (in thousands, except share data) | September 30, 2012 | December 31, 2011 |
|---|---|---|
| LIABILITIES AND EQUITY | | |
| Current Liabilities | | |
| Short-Term Debt | $ 12,417 | $ -- |
| Current Maturities of Long-Term Debt | 173 | 3,033 |
| Accounts Payable | 103,108 | 115,514 |
| Accrued Salaries and Wages | 24,360 | 19,043 |
| Accrued Taxes | 10,359 | 11,841 |
| Derivative Liabilities | 18,869 | 18,770 |
| Other Accrued Liabilities | 6,923 | 5,540 |
| Liabilities of Discontinued Operations | 164 | 13,763 |
| Total Current Liabilities | 176,373 | 187,504 |
| Pensions Benefit Liability | 99,534 | 106,818 |
| Other Postretirement Benefits Liability | 49,876 | 48,263 |
| Other Noncurrent Liabilities | 21,806 | 19,002 |
| Commitments and Contingencies (note 9) | | |
| Deferred Credits | | |
| Deferred Income Taxes | 152,340 | 177,264 |
| Deferred Tax Credits | 31,822 | 33,182 |
| Regulatory Liabilities | 69,396 | 69,106 |
| Other | 449 | 520 |
| Total Deferred Credits | 254,007 | 280,072 |
| Capitalization | | |
| Long-Term Debt, Net of Current Maturities | 421,725 | 471,915 |
| Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2012 and 2011 – 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, 2012—36,164,598 Shares; 2011—36,101,695 Shares | 180,823 | 180,509 |
| Premium on Common Shares | 253,225 | 253,123 |
| Retained Earnings | 100,198 | 141,248 |
| Accumulated Other Comprehensive Loss | (3,141) | (3,432) |
| Total Common Equity | 531,105 | 571,448 |

| | | |
|---|---|---|
| Total Capitalization | 968,330 | 1,058,863 |
| Total Liabilities and Equity | $ 1,569,926 | $ 1,700,522 |

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

| (in thousands, except share and per-share amounts) | Three Months Ended September 30, 2012 | Three Months Ended September 30, 2011 | Nine Months Ended September 30, 2012 | Nine Months Ended September 30, 2011 |
|---|---|---|---|---|
| Operating Revenues | | | | |
| Electric | $88,518 | $85,118 | $257,365 | $254,622 |
| Nonelectric | 188,625 | 197,255 | 581,076 | 560,197 |
| Total Operating Revenues | 277,143 | 282,373 | 838,441 | 814,819 |
| Operating Expenses | | | | |
| Production Fuel - Electric | 20,622 | 19,080 | 48,501 | 55,737 |
| Purchased Power - Electric System Use | 8,138 | 7,488 | 34,624 | 27,759 |
| Electric Operation and Maintenance Expenses | 28,717 | 27,323 | 91,137 | 84,718 |
| Cost of Goods Sold - Nonelectric (excludes depreciation; included below) | 158,703 | 171,157 | 489,305 | 490,737 |
| Other Nonelectric Expenses | 16,438 | 19,114 | 51,118 | 49,204 |
| Asset Impairment Charge | -- | -- | 46,005 | -- |
| Exit and Disposal Costs – DMI Industries, Inc. | 4,400 | -- | 4,400 | -- |
| Depreciation and Amortization | 15,951 | 17,604 | 50,122 | 52,262 |
| Property Taxes - Electric | 2,833 | 2,601 | 8,120 | 7,427 |
| Total Operating Expenses | 255,802 | 264,367 | 823,332 | 767,844 |
| Operating Income | 21,341 | 18,006 | 15,109 | 46,975 |
| | | | | |
| Loss on Early Retirement of Debt | 13,106 | -- | 13,106 | -- |
| Interest Charges | 7,904 | 8,696 | 24,997 | 27,310 |
| Other Income | 689 | 408 | 2,423 | 1,544 |
| Income (Loss) from Continuing Operations Before Income Taxes | 1,020 | 9,718 | (20,571) | 21,209 |
| Income Tax (Benefit) Expense – Continuing Operations | (858) | 2,382 | (15,054) | 3,535 |
| Net Income (Loss) from Continuing Operations | 1,878 | 7,336 | (5,517) | 17,674 |
| Discontinued Operations | | | | |
| (Loss) Income - net of Income Tax (Benefit) Expense of ($2), ($307), $571, and $261 for the respective periods | (5) | (514) | 821 | 420 |
| (Loss) Gain on Disposition - net of Income Tax (Benefit) Expense of $0, ($302), ($169), and $3,213 for the respective periods | -- | (454) | (3,544) | 12,798 |
| Net (Loss) Income from Discontinued Operations | (5) | (968) | (2,723) | 13,218 |
| Net Income (Loss) | 1,873 | 6,368 | (8,240) | 30,892 |
| Preferred Dividend Requirements and Other Adjustments | 183 | 184 | 551 | 874 |
| Earnings Available for Common Shares | $1,690 | $6,184 | $(8,791) | $30,018 |
| | | | | |
| Average Number of Common Shares Outstanding—Basic | 36,061,002 | 35,933,003 | 36,043,276 | 35,911,993 |
| Average Number of Common Shares Outstanding—Diluted | 36,252,765 | 36,171,555 | 36,043,276 | 36,150,545 |
| Basic Earnings Per Common Share: | | | | |
| Continuing Operations | $0.05 | $0.20 | $(0.17) | $0.48 |
| Discontinued Operations | -- | (0.03) | (0.07) | 0.36 |
| | $0.05 | $0.17 | $(0.24) | $0.84 |

| | | | | |
|---|---|---|---|---|
| Diluted Earnings Per Common Share: | | | | |
| Continuing Operations | $0.05 | $0.20 | $(0.17) | $0.47 |
| Discontinued Operations | -- | (0.03) | (0.07) | 0.36 |
| | $0.05 | $0.17 | $(0.24) | $0.83 |
| Dividends Declared Per Common Share | $0.2975 | $0.2975 | $0.8925 | $0.8925 |

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Statements of Comprehensive Income
(not audited)

| (in thousands) | Three Months Ended September 30, 2012 | Three Months Ended September 30, 2011 | Nine Months Ended September 30, 2012 | Nine Months Ended September 30, 2011 |
|---|---|---|---|---|
| Net Income (Loss) | $1,873 | $6,368 | $(8,240) | $30,892 |
| Other Comprehensive Income (Loss): | | | | |
| Unrealized Gain on Available-for-Sale Securities: | | | | |
| Gain (Loss) Arising During Period | 72 | (3) | 180 | 11 |
| Income Tax Expense | (29) | 1 | (72) | (5) |
| Unrealized Gain on Available-for-Sale Securities – net-of-tax | 43 | (2) | 108 | 6 |
| Foreign Currency Translation Adjustment: | | | | |
| Unrealized Net Change During Period | -- | -- | -- | 303 |
| Reversal of Previously Recognized Gains Realized on the Sale of Idaho Pacific Holdings, Inc. (IPH) | -- | -- | -- | (6,068) |
| Income Tax Benefit | -- | -- | -- | 1,788 |
| Foreign Currency Translation Adjustment – net-of-tax | -- | -- | -- | (3,977) |
| Pension and Postretirement Benefit Plans: | | | | |
| Actuarial Loss -- Regulatory Allocation Adjustment (ESSRP) | -- | -- | -- | (1,621) |
| Amortization of Unrecognized Postretirement Benefit Losses and Costs | 101 | 79 | 305 | 963 |
| Income Tax (Expense) Benefit | (41) | (32) | (122) | 263 |
| Pension and Postretirement Benefit Plans – net-of-tax | 60 | 47 | 183 | (395) |
| Total Other Comprehensive Income (Loss) | 103 | 45 | 291 | (4,366) |
| Total Comprehensive Income (Loss) | $1,976 | $6,413 | $(7,949) | $26,526 |

See accompanying notes to consolidated financial statements.

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

| | Nine Months Ended September 30, | |
|---|---|---|
| (in thousands) | 2012 | 2011 |
| Cash Flows from Operating Activities | | |
| Net (Loss) Income | $(8,240) | $30,892 |
| Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities: | | |
| Net Loss (Gain) from Sale of Discontinued Operations | 3,544 | (12,798) |
| Income from Discontinued Operations | (821) | (420) |
| Depreciation and Amortization | 50,122 | 52,262 |
| Asset Impairment Charge | 46,005 | -- |
| Premium Paid for Early Retirement of Long-Term Debt | 12,500 | -- |
| Deferred Tax Credits | (1,568) | (1,834) |
| Deferred Income Taxes | (3,513) | 10,117 |
| Change in Deferred Debits and Other Assets | 16,493 | 11,976 |
| Discretionary Contribution to Pension Plan | (10,000) | -- |
| Change in Noncurrent Liabilities and Deferred Credits | 7,129 | 1,690 |
| Allowance for Equity (Other) Funds Used During Construction | (518) | (576) |
| Change in Derivatives Net of Regulatory Deferral | 752 | (177) |
| Stock Compensation Expense – Equity Awards | 930 | 1,760 |
| Other—Net | 821 | 1,107 |
| Cash (Used for) Provided by Current Assets and Current Liabilities: | | |
| Change in Receivables | (3,815) | (36,575) |
| Change in Inventories | 4,552 | (11,866) |
| Change in Other Current Assets | 43,202 | 10,225 |
| Change in Payables and Other Current Liabilities | 2,748 | 6,472 |
| Change in Interest and Income Taxes Receivable/Payable | (12,263) | 280 |
| Net Cash Provided by Continuing Operations | 148,060 | 62,535 |
| Net Cash Provided by Discontinued Operations | 1,322 | 17,837 |
| Net Cash Provided by Operating Activities | 149,382 | 80,372 |
| Cash Flows from Investing Activities | | |
| Capital Expenditures | (96,548) | (60,431) |
| Proceeds from Disposal of Noncurrent Assets | 5,478 | 1,859 |
| Net (Increase) Decrease in Other Investments | (1,385) | 334 |
| Net Cash Used in Investing Activities - Continuing Operations | (92,455) | (58,238) |
| Net Proceeds from Sale of Discontinued Operations | 24,278 | 84,330 |
| Net Cash Used in Investing Activities - Discontinued Operations | (11,705) | (15,875) |
| Net Cash (Used in) Provided by Investing Activities | (79,882) | 10,217 |
| Cash Flows from Financing Activities | | |
| Change in Checks Written in Excess of Cash | 4,402 | (8,464) |
| Net Short-Term Borrowings (Repayments) | 12,417 | (40,415) |
| Payments for Retirement of Common Stock and Common Stock Issuance Expenses | (291) | (152) |
| Proceeds from Issuance of Long-Term Debt | -- | 2,007 |
| Short-Term and Long-Term Debt Issuance Expenses | (14) | (1,577) |
| Payments for Retirement of Long-Term Debt | (53,051) | (368) |
| Premium Paid for Early Retirement of Long-Term Debt | (12,500) | -- |

| | | |
|---|---|---|
| Dividends Paid and Other Distributions | (33,033 ) | (33,011 ) |
| Net Cash Used in Financing Activities - Continuing Operations | (82,070 ) | (81,980 ) |
| Net Cash Used in Financing Activities - Discontinued Operations | (1,409 ) | (1,681 ) |
| Net Cash Used in Financing Activities | (83,479 ) | (83,661 ) |
| Net Change in Cash and Cash Equivalents - Discontinued Operations | (673 ) | 921 |
| Effect of Foreign Exchange Rate Fluctuations on Cash – Discontinued Operations | -- | (324 ) |
| Net Change in Cash and Cash Equivalents | (14,652 ) | 7,525 |
| Cash and Cash Equivalents at Beginning of Period | 14,652 | -- |
| Cash and Cash Equivalents at End of Period | $-- | $7,525 |

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments necessary for a fair presentation of the condensed consolidated financial statements for the periods presented. The condensed 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, 2011, 2010 and 2009 included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2011. Because of seasonal and other factors, the earnings for the three and nine month periods ended September 30, 2012 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, 2011.

1. Summary of Significant Accounting Policies

Revenue Recognition
Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, and the price is fixed or determinable. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as Otter Tail Power Company (OTP) forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with the Financial Accounting Standards Board Accounting Standards Codification (ASC) 815, Derivatives and Hedging. 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 in the Company's Wind Energy, Manufacturing and Construction segments enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The method used to determine the progress of completion is based on the ratio of labor hours incurred to total estimated labor hours at the Company's wind tower manufacturer and costs incurred to total estimated costs on all other construction projects.

The Company has a standard quarterly Estimate at Completion (EAC) process in which management reviews the progress and performance of the Company's contracts accounted for under percentage-of-completion accounting. As part of this process, management reviews include, but are not limited to, any outstanding key contract matters, progress towards completion and the related program schedule, identified risks and opportunities, and the related changes in estimates of revenues and costs. The risks and opportunities include management's judgment about the ability and cost to achieve the schedule, technical requirements and other contract requirements. Management must make assumptions regarding labor productivity and availability, the complexity of the work to be performed, the availability of materials, the length of time to complete the contract, and performance by subcontractors, among other variables. Based on this analysis, any adjustments to net sales, costs of sales, and the related impact to operating income are recorded as necessary in the period they become known. These adjustments may result from positive program performance and an increase in operating profit during the performance of individual contracts if management determines it will be successful in mitigating risks surrounding the technical, schedule, and cost aspects of those contracts or realizing related opportunities. Likewise, these adjustments may result in a decrease in operating profit if management determines it will not be successful in mitigating these risks or realizing related opportunities. Changes in estimates of net sales, costs of sales, and the related impact to operating income are recognized using a cumulative catch-up, which recognizes, in the current period, the cumulative effect of the changes on current and prior periods based on a contract’s percent complete. A significant change in one or more of these estimates could affect the profitability of one or more of the Company’s contracts. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized.

Following are the percentages of the Company's consolidated revenues recorded under the percentage-of-completion method:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Percentage-of-Completion Revenues | 34.5 % | 39.0 % | 34.3 % | 37.6 % |

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

| (in thousands) | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Costs Incurred on Uncompleted Contracts | $ 448,039 | $ 583,346 |
| Less Billings to Date | (454,803 ) | (550,070 ) |
| Plus Estimated Earnings Recognized | 17,091 | 24,478 |
| Net Costs Incurred in Excess of Billings and Accrued Revenues on Uncompleted Contracts | $ 10,327 | $ 57,754 |

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, 2012 | December 31, 2011 |
|---|---|---|
| Costs and Estimated Earnings in Excess of Billings | $ 23,900 | $ 67,109 |
| Billings in Excess of Costs and Estimated Earnings | (13,573 ) | (9,355 ) |
| Net Costs Incurred in Excess of Billings and Accrued Revenues on Uncompleted Contracts | $ 10,327 | $ 57,754 |

Included in Costs and Estimated Earnings in Excess of Billings are the following amounts at DMI Industries, Inc. (DMI), the Company's wind tower manufacturer:

| (in thousands) | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts - DMI | $ 17,609 | $ 54,541 |

These amounts are 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.

Warranty Reserves

The Company establishes reserves for estimated product warranty costs at the time revenue is recognized based on historical warranty experience and additionally for any known product warranty issues. Certain Company products carry one to fifteen year warranties. Although the Company engages in extensive product quality programs and processes, the Company's warranty obligations have been and may in the future be affected by product failure rates, repair or field replacement costs and additional development costs incurred in correcting product failures.

(in thousands)

| | | |
|---|---|---|
| Warranty Reserve Balance, December 31, 2011 | $ | 3,170 |
| Provision for Warranties Issued During the Year | | 761 |
| Settlements Made During the Year | | (880 ) |
| Adjustments to Warranty Estimates for Prior Years | | (71 ) |
| Warranty Reserve Balance, September 30, 2012 | $ | 2,980 |

Expenses associated with remediation activities in the Wind Energy segment could be substantial. The potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. If the Company is required to cover remediation expenses in addition to regular warranty coverage, the Company could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect the Company's consolidated results of operations and financial condition.

Retainage
Accounts Receivable include the following amounts, billed under contracts by the Company's subsidiaries, that have been retained by customers pending project completion:

| (in thousands) | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Accounts Receivable Retained by Customers | $ 13,224 | $ 13,526 |

Sales of Receivables
DMI previously was a party to a $40 million receivables sales agreement whereby designated customer accounts receivable were sold to General Electric Capital Corporation (GECC) on a revolving basis. This agreement was terminated effective April 26, 2012. 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.

Following are the amounts of accounts receivable sold under DMI's receivables sales agreement with GECC:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (in thousands) | 2012 | 2011 | 2012 | 2011 |
| Accounts Receivable Sold | $- | $20,662 | $32,115 | $48,802 |

Fair Value Measurements
The Company follows ASC 820, Fair Value Measurements and Disclosures, for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and 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.

Fair values for OTP's forward energy contracts as of September 30, 2012, included in level 3 of the fair value hierarchy in the table below are based on prices indexed to observable prices at an active trading hub for contracts with delivery points that are not at the active trading hub.

The following tables present, 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, 2012 and December 31, 2011:

| September 30, 2012 (in thousands) | Level 1 | Level 2 | Level 3 |
|---|---|---|---|
| Assets: | | | |
| Current Assets – Other: | | | |
| Forward Energy Contracts | $ -- | $ 977 | $ 1,242 |
| Forward Gasoline Purchase Contracts | | 192 | |
| Money Market Fund - Escrow Account IPH Sale | 1,500 | | |
| Money Market and Mutual Funds - Nonqualified Retirement Savings Plan | 110 | | |
| Investments: | | | |
| Corporate Debt Securities – Held by Captive Insurance Company | | 8,028 | |
| U.S. Government Debt Securities – Held by Captive Insurance Company | | 1,312 | |
| Other Assets: | | | |
| Money Market and Mutual Funds - Nonqualified Retirement Savings Plan | 107 | | |
| Equity Securities - Nonqualified Retirement Savings Plan | 129 | | |
| Total Assets | $ 1,846 | $ 10,509 | $ 1,242 |
| Liabilities: | | | |
| Derivative Liabilities: | | | |
| Forward Energy Contracts | $ -- | $ 3,413 | $ 15,456 |
| Total Liabilities | $ -- | $ 3,413 | $ 15,456 |

In 2012, the Company's investments in forward gasoline contracts and U.S. government debt securities were moved to level 2 of the fair value hierarchy and the regulatory assets and liabilities are no longer included in the fair value table.

| December 31, 2011 (in thousands) | Level 1 | Level 2 | Level 3 |
|---|---|---|---|
| Assets: | | | |
| Current Assets – Other: | | | |
| Forward Energy Contracts | $ -- | $ 3,803 | |
| Forward Gasoline Purchase Contracts | 9 | | |
| Money Market Fund - Escrow Account IPH Sale | 1,500 | | |
| Money Market and Mutual Funds - Nonqualified Retirement Savings Plan | 110 | | |
| Regulatory Assets – Current: | | | |
| Deferred Mark-to-Market Losses on Forward Energy Contracts | | 5,208 | |
| Investments: | | | |
| Corporate Debt Securities – Held by Captive Insurance Company | | 8,083 | |
| U.S. Government Debt Securities – Held by Captive Insurance Company | 707 | | |
| Money Market Fund - Escrow Account IPH Sale | 1,501 | | |
| Other Assets: | | | |
| Money Market and Mutual Funds - Nonqualified Retirement Savings Plan | 254 | | |

| | | | | |
|---|---|---|---|---|
| Regulatory Assets – Deferred: | | | | |
| Deferred Mark-to-Market Losses on Forward Energy Contracts | | | | 10,749 |
| Total Assets | $ | 4,081 | $ | 27,843 |
| Liabilities: | | | | |
| Derivative Liabilities - Forward Energy Contracts | $ | -- | $ | 18,770 |
| Regulatory Liabilities – Current: | | | | |
| Deferred Mark-to-Market Gains on Forward Energy Contracts | | | | 96 |
| Total Liabilities | $ | -- | $ | 18,866 |

## Inventories

Inventories consist of the following:

| (in thousands) | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Finished Goods | $ 20,306 | $ 21,373 |
| Work in Process | 11,302 | 11,951 |
| Raw Material, Fuel and Supplies | 41,822 | 44,659 |
| Total Inventories | $ 73,430 | $ 77,983 |

## Asset Impairment Charge

The Company entered into a nonbinding letter of interest in June 2012 with Trinity Industries, Inc. (Trinity), based in Dallas, Texas, to sell the fixed assets of DMI for $20 million, with the Company retaining DMI’s net working capital—approximately $66 million on June 30, 2012. On September 6, 2012 the Company entered into definitive agreements with Trinity to sell the fixed assets of DMI for $20 million. The agreed on price for the fixed assets is an indicator of the fair value of the assets under level 2 of the ASC fair value hierarchy and also is considered an indication of a decrease in the market value of the assets being sold. This decrease in market value has been significantly impacted by the severe decline in market conditions in the wind energy industry. The Federal Production Tax Credit (PTC) for investments in renewable energy resources is expected to expire at the end of 2012. DMI has no tower orders for 2013 given the expected expiration of the PTC. These factors resulted in DMI recording a nonrecurring fair value adjustment of its long-lived assets to the indicated market price of $20 million and a noncash asset impairment charge of $45.6 million ($27.5 million net-of-tax benefits), or $0.76 per share, in June 2012 broken down as follows:

| (in thousands) | |
|---|---|
| Long-Lived Assets | $ 90,846 |
| Accumulated Depreciation – Long-Lived Assets | (45,561) |
| Goodwill | 288 |
| Total Asset Impairment Charges | $ 45,573 |

The sale of the Fort Erie fixed assets closed on September 6, 2012, the West Fargo transaction closed on October 31, 2012 and the Tulsa transaction is expected to close on November 30, 2012. Under the terms of the definitive agreements, DMI must complete its current backlog of towers ordered for delivery in 2012 before each closing can occur. Under these circumstances, accounting rules require that DMI’s assets and results of operations continue to be reported as continuing operations. However, on completion of all remaining tower orders, DMI’s assets will be considered available for immediate sale and the Company expects DMI’s results and any remaining assets will be reported under discontinued operations at the end of 2012.

## Goodwill and Other Intangible Assets

The following table summarizes changes to goodwill by business segment during 2012:

| (in thousands) | Gross Balance December 31, 2011 | Accumulated Impairments | Balance (net of impairments) December 31, 2011 | Adjustments to Goodwill in 2012 | Balance (net of impairments) September 30, 2012 |
|---|---|---|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Electric | $ 240 | $ (240 ) | $ -- | $ -- | $ -- |
| Wind Energy | 288 | -- | 288 | (288 ) | -- |
| Manufacturing | 24,445 | (12,259 ) | 12,186 | -- | 12,186 |
| Construction | 7,630 | -- | 7,630 | 1 | 7,631 |
| Plastics | 19,302 | -- | 19,302 | -- | 19,302 |
| Total | $ 51,905 | $ (12,499 ) | $ 39,406 | $ (287 ) | $ 39,119 |

Other Intangible Assets
The following table summarizes the components of the Company's intangible assets at September 30, 2012 and December 31, 2011:

| September 30, 2012 (in thousands) | Gross Carrying Amount | Accumulated Amortization | Net Carrying Amount | Amortization Periods |
|---|---|---|---|---|
| Amortizable Intangible Assets: | | | | |
| Customer Relationships | $ 16,811 | $ 3,873 | $ 12,938 | 15 – 25 years |
| Other Intangible Assets Including Contracts | 1,092 | 581 | 511 | 5 – 30 years |
| Total | $ 17,903 | $ 4,454 | $ 13,449 | |
| Indefinite-lived Intangible Assets: | | | | |
| Trade Name | $ 1,100 | -- | $ 1,100 | |
| | | | | |
| December 31, 2011 (in thousands) | | | | |
| Amortizable Intangible Assets: | | | | |
| Customer Relationships | $ 16,811 | $ 3,236 | $ 13,575 | 15 – 25 years |
| Covenants Not to Compete | 713 | 709 | 4 | 3 – 5 years |
| Other Intangible Assets Including Contracts | 1,092 | 485 | 607 | 5 – 30 years |
| Total | $ 18,616 | $ 4,430 | $ 14,186 | |
| Indefinite-lived Intangible Assets: | | | | |
| Trade Name | $ 1,100 | -- | $ 1,100 | |

The amortization expense for these intangible assets was:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (in thousands) | 2012 | 2011 | 2012 | 2011 |
| Amortization Expense – Intangible Assets | $244 | $215 | $737 | $657 |

The estimated annual amortization expense for these intangible assets for the next five years is:

| (in thousands) | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|
| Estimated Amortization Expense – Intangible Assets | $981 | $977 | $977 | $977 | $945 |

Supplemental Disclosures of Cash Flow Information

| | As of September 30, | |
|---|---|---|
| (in thousands) | 2012 | 2011 |
| Noncash Investing Activities: | | |
| Accounts Payable Outstanding Related to Capital Additions1 | $5,979 | $2,878 |

1Amounts are included in cash used for capital expenditures in subsequent periods when payables are settled.

Reclassifications and Changes to Presentation
The Company's consolidated statements of income for the three and nine month periods ended September 30, 2011 and consolidated statement of cash flows for the nine months ended September 30, 2011 reflect the reclassifications of the operating results and cash flows of E.W. Wylie Corporation (Wylie), DMS Health Technologies, Inc. (DMS), and Aviva Sports, Inc. (Aviva), a wholly owned subsidiary of ShoreMaster, Inc. (ShoreMaster), to discontinued operations

as a result of the December 2011 sale of Wylie, the January 2012 sale of Aviva and the February 2012 sale of DMS. The reclassifications had no impact on the Company's total consolidated net income or cash flows for the three or nine month periods ended September 30, 2011.

2. Segment Information

The Company's businesses have been classified into five reportable segments to be consistent with its business strategy and the reporting and review process used by the Company's chief operating decision makers. These businesses sell products and provide services to customers primarily in the United States. The five segments are: Electric, Wind Energy, Manufacturing, Construction and Plastics.

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 operations have been the Company's primary business since 1907. Additionally, the electric segment includes Otter Tail Energy Services Company (OTESCO), which provides technical and engineering services.

Wind Energy consists of DMI, a steel fabrication company primarily involved in the production of wind towers sold in the United States and Canada, with manufacturing facilities in North Dakota and Oklahoma. The Company will discontinue the production of wind towers and expects to complete the sale of DMI's production facilities and exit the wind tower production business in the fourth quarter of 2012.

Manufacturing consists of businesses in the following manufacturing activities: 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 and Minnesota and sell products primarily in the United States.

Construction consists of businesses involved in industrial electric contracting and construction of fiber optic and electric distribution systems, water, wastewater and HVAC systems primarily in the central United States.

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

OTP and OTESCO are wholly owned subsidiaries of the Company. All of the Company's other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar).

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

The Company had one customer within the Wind Energy segment that accounted for 10.8% of the Company's consolidated revenues in 2011. All of the Company's long-lived assets are located within the United States.

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

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2012 | | 2011 | |
| United States of America | 98.1 | % | 98.2 | % | 97.8 | % | 98.3 | % |
| Canada | 1.0 | % | 1.3 | % | 1.4 | % | 1.4 | % |
| All Other Countries | 0.9 | % | 0.5 | % | 0.8 | % | 0.3 | % |

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 the three and nine month periods ended September 30, 2012 and total assets by business segment as of September 30, 2012 and December 31, 2011 are presented in the following tables:

Operating Revenue

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (in thousands) | 2012 | 2011 | 2012 | 2011 |
| Electric | $ 88,564 | $ 85,172 | $ 257,530 | $ 254,799 |
| Wind Energy | 55,025 | 52,595 | 169,745 | 154,608 |
| Manufacturing | 53,567 | 55,625 | 183,142 | 168,306 |
| Construction | 37,931 | 53,247 | 111,482 | 139,895 |
| Plastics | 42,217 | 36,231 | 118,582 | 99,082 |
| Corporate Revenues and Intersegment Eliminations | (161 ) | (497 ) | (2,040 ) | (1,871 ) |
| Total | $ 277,143 | $ 282,373 | $ 838,441 | $ 814,819 |

Interest Expense

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (in thousands) | 2012 | 2011 | 2012 | 2011 |
| Electric | $ 4,880 | $ 4,796 | $ 14,493 | $ 14,874 |
| Wind Energy | 1,499 | 1,775 | 4,813 | 5,334 |
| Manufacturing | 1,279 | 1,229 | 3,968 | 3,695 |
| Construction | 305 | 251 | 868 | 698 |
| Plastics | 342 | 411 | 1,034 | 1,176 |
| Corporate and Intersegment Eliminations | (401 ) | 234 | (179 ) | 1,533 |
| Total | $ 7,904 | $ 8,696 | $ 24,997 | $ 27,310 |

Income Taxes

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (in thousands) | 2012 | 2011 | 2012 | 2011 |
| Electric | $ 2,995 | $ 3,364 | $ 3,817 | $ 5,972 |
| Wind Energy | (114 ) | (383 ) | (16,081 ) | (4,106 ) |
| Manufacturing | 574 | 780 | 3,701 | 4,132 |
| Construction | (879 ) | (115 ) | (4,819 ) | (195 ) |
| Plastics | 2,216 | 1,295 | 7,113 | 3,198 |
| Corporate | (5,650 ) | (2,559 ) | (8,785 ) | (5,466 ) |
| Total | $ (858 ) | $ 2,382 | $ (15,054 ) | $ 3,535 |

Earnings Available for Common Shares

Three Months Ended Nine Months Ended

| (in thousands) | September 30, 2012 | 2011 | September 30, 2012 | 2011 |
|---|---|---|---|---|
| Electric | $ 10,206 | $ 10,900 | $ 26,413 | $ 29,428 |
| Wind Energy | (2,974) | (2,770) | (28,597) | (15,568) |
| Manufacturing | 833 | 1,366 | 5,464 | 6,793 |
| Construction | (1,325) | (179) | (7,252) | (320) |
| Plastics | 3,309 | 1,970 | 10,629 | 4,908 |
| Corporate | (8,354) | (4,135) | (12,725) | (8,119) |
| Discontinued Operations | (5) | (968) | (2,723) | 12,896 |
| Total | $ 1,690 | $ 6,184 | $ (8,791) | $ 30,018 |

Identifiable Assets

| (in thousands) | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Electric | $ 1,179,472 | $ 1,170,449 |
| Wind Energy | 47,610 | 149,234 |
| Manufacturing | 149,715 | 154,908 |
| Construction | 67,342 | 69,453 |
| Plastics | 86,445 | 72,200 |
| Corporate | 38,612 | 54,586 |
| Discontinued Operations | 730 | 29,692 |
| Total | $ 1,569,926 | $ 1,700,522 |

3. Rate and Regulatory Matters

Minnesota

2010 General Rate Case Filing—OTP filed a general rate case on April 2, 2010 requesting an 8.01% base rate increase as well as a 3.8% interim rate increase. On May 27, 2010, the Minnesota Public Utilities Commission (MPUC) issued an order accepting the filing, suspending rates, and approving the interim rate increase, as requested, to be effective with customer usage on and after June 1, 2010. The MPUC held a hearing to decide on the issues in the rate case on March 25, 2011 and issued a written order on April 25, 2011. The MPUC authorized a revenue increase of approximately $5.0 million, or 3.76% in base rate revenues, excluding the effect of moving recovery of wind investments to base rates. The MPUC's written order included: (1) recovery of Big Stone II costs over five years, (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of Minnesota Conservation Improvement Program (MNCIP) costs from rider recovery to base rate recovery, (4) transfer of the investment in two transmission lines from rider recovery to base rate recovery, and (5) changing the mechanism for providing customers with a credit for margins earned on asset-based wholesale sales of electricity from a credit to base rates to a credit to the Minnesota Fuel Clause Adjustment. Final rates went into effect October 1, 2011. The overall increase to customers was approximately 1.6% compared to the authorized interim rate increase of 3.8%, which resulted in an interim rate refund to Minnesota retail electric customers of approximately $3.9 million in the fourth quarter of 2011. Pursuant to the order, OTP's allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased from 10.43% to 10.74%. OTP's authorized rates of return are based on a capital structure of 48.28% long term debt and 51.72% common equity.

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

Under the Next Generation Energy Act of 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover investments and costs incurred to satisfy the requirements of the renewable energy standard. The MPUC is authorized to approve a rate schedule rider to enable utilities to recover the costs of qualifying renewable energy projects that supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

The MPUC issued an order on January 12, 2010 finding OTP's Luverne Wind Farm project eligible for cost recovery through the Minnesota Renewable Resource Adjustment (MNRRA). The 2010 annual MNRRA cost recovery filing was made on December 31, 2009 with a requested effective date of April 1, 2010. The MPUC approved OTP's petition for a 2010 MNRRA in the third quarter of 2010 with implementation effective September 1, 2010. The 2010 MNRRA was in place from September 1, 2010 through September 30, 2011 with a recovery of $17.0 million.

The recovery of MNRRA costs was moved to base rates as of October 1, 2011 under the MPUC's April 25, 2011 general rate case order with the exception of the remaining balance of the MNRRA regulatory asset. OTP has a regulatory asset of $1.4 million for revenues that are eligible for recovery through the MNRRA rider that have not been billed to Minnesota customers as of September 30, 2012. A request for an updated rate to be effective October 1, 2012 was initially filed on June 28, 2012, followed by a revised filing on July 25, 2012. The filing, which is still under review, included a request to extend the period of the new rate for 18 months, which would reduce the current balance of unrecovered costs to zero.

Transmission Cost Recovery (TCR) Rider—In addition to the MNRRA rider, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule.

OTP requested recovery of its transmission investments being recovered through its Minnesota TCR rider rate as part of its general rate case filed on April 2, 2010. In its April 25, 2011 general rate case order, the MPUC approved the transfer of transmission costs currently being recovered through OTP's Minnesota TCR rider to recovery in base rates. Final rates went into effect on October 1, 2011. The Company will continue to utilize the rider cost recovery mechanism until the remaining balance of the current transmission projects has been collected as well as to recover costs associated with approved regional projects. OTP filed a request for an update to its Minnesota TCR rider on October 5, 2010. The update to OTP's Minnesota TCR rider, approved by the MPUC on March 26, 2012, went into effect April 1, 2012.

In this TCR rider update, the MNPUC addressed how to handle utility investments in transmission facilities that qualify for regional cost allocation under the MISO tariff. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from the other MISO utilities. The MPUC considered two possible approaches to recovery of OTP's transmission investments in excess of amounts allocated back to its retail load-serving obligations: (1) a split method in which OTP's Minnesota retail customers would be responsible only for the investment allocated back to OTP through the MISO tariff, or (2) an all-in method in which OTP's retail customers would be responsible for the entire investment OTP made with an offsetting credit for revenues received from other MISO utilities under the MISO tariff. The MPUC approved using the all-in method on March 26, 2012.

On May 24, 2012 OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of twelve additional transmission related projects in subsequent Minnesota TCR rider filings. On August 22, 2012 the Minnesota Department of Commerce (MNDOC) filed comments and on August 24, 2012 the Minnesota Office of the Attorney General filed comments. OTP filed reply comments on September 25, 2012. If approval is obtained to include additional projects in the rider, investment in the approved projects will be included in the next annual Minnesota TCR rider rate update filings and recovery of the investment will begin through the TCR rider rates if subsequently approved by the MPUC. Updated costs associated with existing projects within the Minnesota TCR rider will also be included in the next annual rider rate update filing. OTP has a regulatory liability of $0.3 million for revenues that are subject to refund through the Minnesota TCR rider that have been billed to Minnesota customers as of September 30, 2012.

Conservation Improvement Programs—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota. The Next Generation Energy Act of 2007, passed by the Minnesota legislature in May 2007, transitions from a conservation spending goal to a conservation energy savings goal. On July 1, 2010 OTP filed its plan for 2011-2013. MNDOC may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

A written order was issued by the MPUC on January 11, 2012 approving the recovery of $3.5 million for the 2010 MNCIP financial incentives. Beginning in January 2012, OTP's MNCIP Conservation Cost Recovery Adjustment (CCRA) increased from 3.0% to 3.8% for all Minnesota retail electric customers. On March 30, 2012 OTP submitted its annual 2011 financial incentive filing request for $2.6 million. On October 16, 2012 MNDOC recommended that the MPUC approve OTP's 2011 financial incentive of $2.6 million.

Starting with the next surcharge rate to be charged to MNCIP customers, OTP expects the method used for charging the CCRA to change from a percentage of a customer's bill to an amount per kilowatt-hour (kwh) consumed. The per-kwh cost allocation method has been the principle method approved by the MNPUC for other electric utilities in Minnesota. Under this method, conservation costs are allocated equally to each unit of energy sold and all OTP Minnesota customers would pay the same conservation surcharge rate for each kwh consumed. OTP's proposed surcharge under the per-kwh method is equivalent to 3.1% of total retail revenues collected from Minnesota customers.

OTP has a regulatory asset of $5.5 million for allowable costs and financial incentives that are eligible for recovery through the MNCIP rider that have not been billed to Minnesota customers as of September 30, 2012. OTP recognized revenue for Minnesota conservation costs and incentives earned totaling $1.5 million and $4.8 million, respectively, in the three and nine month periods ended September 30, 2012, compared with $1.1 million and $5.9 million, respectively, in the three and nine month periods ended September 30, 2011.

North Dakota

Renewable Resource Cost Recovery Rider—The 2010 North Dakota Renewable Resource Adjustment (NDRRA) was in place for the period of September 1, 2010 through March 31, 2012 with a recovery of $15.6 million. On December 29, 2011 OTP submitted its annual update to the renewable rider with an April 1, 2012 effective date. OTP's request for an updated NDRRA was approved by the North Dakota Public Service Commission (NDPSC) on March 21, 2012 and went into effect April 1, 2012. The 2011 NDRRA has an expected recovery of $10.1 million over the period April 1, 2012 through March 31, 2013. OTP has a regulatory asset of $1.9 million for revenues that are eligible for recovery through the NDRRA rider that have not been billed to North Dakota customers as of September 30, 2012.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. OTP filed a request for an initial North Dakota TCR rider with the NDPSC on April 29, 2011. On April 25, 2012 the NDPSC approved the use of the split method of cost recovery for the North Dakota TCR rider and the rider rate to be effective May 1, 2012. On August 31, 2012, OTP filed its annual update to the North Dakota TCR rider rate to reflect updated cost information associated with projects currently in the rider, as well as proposing to include costs associated with ten additional projects for recovery within the rider. OTP is proposing the new rate to be effective January 1, 2013. OTP has a regulatory asset of $0.6 million for revenues that are eligible for recovery through the North Dakota TCR rider that have not been billed to North Dakota customers as of September 30, 2012.

South Dakota

2010 General Rate Case Filing—On August 20, 2010 OTP filed a general rate case with the South Dakota Public Utilities Commission (SDPUC) requesting an overall revenue increase of approximately $2.8 million, or just under 10.0%, which includes, among other things, recovery of investments and expenses related to renewable resources. On September 28, 2010 the SDPUC suspended OTP's proposed rates for a period of 180 days to allow time to review OTP's proposal. On January 19, 2011 OTP submitted a proposal to use current rate design to implement an interim rate in South Dakota to be effective on and after February 17, 2011. On January 26, 2011 OTP submitted an amended proposal to use a lower interim rate increase than originally proposed. At its February 1, 2011 meeting, the SDPUC approved OTP's request to implement interim rates using current rate design and the lower interim increase to be effective on and after February 17, 2011. On April 21, 2011, the SDPUC issued its written order approving an overall final revenue increase of approximately $643,000 (2.32%) and an overall rate of return on rate base of 8.50% for the interim rates and final rates. Final rates were effective with bills rendered on and after June 1, 2011.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. OTP submitted a request for an initial South Dakota TCR rider to the SDPUC on November 5, 2010. The South Dakota TCR was approved by the SDPUC and implemented on December 1, 2011. On September 4, 2012, OTP filed its annual update to the South Dakota TCR rider rate with a proposed effective date of January 1, 2013. OTP has a regulatory liability of $0.1 million for revenues that are subject to refund through the South Dakota TCR rider that have been billed to South Dakota customers as of September 30, 2012.

Federal

Wholesale power sales and transmission rates are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Federal Power Act of 1935, as amended. The FERC is an independent agency, with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one day suspension period, subject to ultimate approval by the FERC.

Effective January 1, 2010, the FERC authorized OTP’s implementation of a forward looking formula transmission rate under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). OTP was also authorized by the FERC to recover: (1) in its formula rate 100% of prudently incurred Construction Work in Progress (CWIP) in rate base and (2) 100% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP’s control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, specifically for three regional transmission CapX2020 projects that OTP is investing in, including the Fargo project, Bemidji project and Brookings project.

On December 16, 2010, FERC approved the cost allocation for a new classification of projects in MISO called Multi-Value Projects (MVP). MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011, FERC reaffirmed the MVP cost allocation on Rehearing. The MVP cost allocation is currently being challenged at the United States Court of Appeals, Seventh Circuit.

Effective January 1, 2012, the FERC authorized OTP to recover 100% CWIP and Abandoned Plant Recovery on two projects approved by MISO as MVP’s in MISO’s 2011 Transmission Expansion Plan: the Big Stone South – Brookings MVP and the Ellendale – Big Stone South MVP.

The Big Stone South – Brookings Project—OTP is jointly developing this project with Xcel Energy. MISO approved this project as an MVP under the MISO Tariff in December 2011. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. A portion of this line is anticipated to use previously obtained Big Stone II transmission route permits and easements and is expected to be in service in 2017. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP. OTP expects to file, in the fourth quarter of 2012 or first quarter of 2013, a request with the SDPUC for recertification of a portion of the line route that was approved as part of the Big Stone II transmission development. OTP and Xcel Energy expect to make a joint route permit filing in the second quarter of 2013 for the remaining portion of the project.

The Ellendale – Big Stone South Project—OTP is jointly developing this project with Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU).  MISO approved this project as an MVP under the MISO Tariff in December 2011. OTP and MDU jointly filed an NICF with the SDPUC in March of 2012. This project will require regulatory approval from both the SDPUC and the NDPSC. Route permits are expected to be filed with the respective commissions in the third quarter of 2013.

Capacity Expansion 2020 (CapX2020)

CapX2020 is a joint initiative of eleven investor-owned, cooperative, and municipal utilities in Minnesota and the surrounding region to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service. The CapX2020 companies identified four major transmission projects for the region: (1) the Fargo–Monticello 345 kiloVolt (kV) Project (the Fargo Project), (2) the Brookings–Southeast Twin Cities 345 kV Project (the Brookings Project), (3) the Bemidji–Grand Rapids 230 kV Project (the Bemidji Project), and (4) the Twin Cities–LaCrosse 345 kV Project. OTP is an investor in the Fargo Project, the Brookings Project and the Bemidji Project. Recovery of OTP's CapX2020 transmission investments will be through the MISO Tariff (the Brookings Project as an MVP) and Minnesota, North Dakota and South Dakota TCR Riders.

The Fargo Project—The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011.

The MPUC approved a route permit for the St. Cloud to Fargo portion of the Fargo Project on June 24, 2011. The agreements for Phase 2, which consists of the line section between St. Cloud and Alexandria, Minnesota, were signed by all of the participants on August 3, 2011. Construction on Phase 2 began in November 2011 and is expected to be completed in the fourth quarter of 2013.

A combined North Dakota Certificate of Corridor Compatibility and route permit application was submitted to the NDPSC on October 3, 2011 and was approved on September 12, 2012. The project owners executed project agreements for Phase 3 on September 28, 2012. An appeal of the North Dakota route permit and a motion for stay of the NDPUC order was filed with the North Dakota District Court on October 12, 2012 by the City of Oxbow and several landowners. The in-service date for the entire project is expected to be 2015; however, this is conditioned on a dismissal of the route permit appeal and motion for stay.

The Brookings Project—The MPUC approved the final line segment route permit for the Brookings Project on February 3, 2011. OTP executed project agreements with co-owners on January 13, 2012. The NDPSC approved the request for an Advanced Determination of Prudence (ADP) on November 10, 2011. The South Dakota route permit was approved by the SDPUC in June 2011. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. This project will be placed in service in segments with the earliest segment being placed in service in the summer of 2013 and the last segment placed in service during the first quarter of 2015.

The Bemidji Project—OTP serves as the lead utility for the Bemidji Project. The MPUC approved the CON for this project on July 9, 2009. A route permit application was approved by the MPUC on October 28, 2010. The joint state and federal Environmental Impact Statement was published by federal agencies on September 7, 2010, and the project's Transmission Capacity Exchange Agreement was accepted and approved by the FERC in the third quarter of 2010. On March 25, 2011, the Leech Lake Band of Ojibwe (LLBO) submitted a petition to the MPUC, requesting the revocation or suspension of the project's route permit. The request is based on the LLBO's allegation that it has jurisdiction to require the project to obtain its permission to cross through the historical boundaries of the Leech Lake Reservation. The owners of the Bemidji Project, including OTP, filed reply comments in opposition to the LLBO's request. On April 25, 2011, the Bemidji Project owners filed a declaratory judgment in the U.S. District Court for Minnesota against the LLBO seeking a judgment that no consent from the LLBO is required for the project to run through the LLBO reservation boundaries since the project is located exclusively on non LLBO lands. On August 6, 2012 a Consent Order Approving Stipulation for Entry of Consent Decree was issued in federal court, which enjoins the LLBO from interfering with the construction, operation, maintenance or repair of the transmission line. In conjunction with the stipulated agreement, the tribal court dismissed the LLBO's action and the LLBO has withdrawn its petition to the MPUC. The dispute between the LLBO and the Bemidji Project is now resolved as the parties have agreed on a confidential settlement. The Bemidji-Grand Rapids transmission line was fully energized and put into service on September 17, 2012.

Big Stone Air Quality Control System

The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant is subject to Best Available Retrofit Technology (BART) requirements of the Clean Air Act (CAA), based on air dispersion modeling indicating that Big Stone's emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan. Under the U.S. Environmental Protection Agency's (EPA) regional haze regulations, South Dakota developed and submitted its implementation plan and associated implementation rules to the EPA on January 21, 2011. The DENR and EPA have agreed on non-substantive rule revisions, which were adopted by the Board of Minerals and Environment and became effective on September 19, 2011.

South Dakota developed and submitted its revised implementation plan and associated implementation rules to EPA on September 19, 2011. Under the South Dakota implementation plan, and its implementing rules, the Big Stone Plant must install and operate a new BART compliant air quality control system to reduce emissions as expeditiously as practicable, but no later than five years after the EPA's approval of South Dakota's implementation plan. On March 29, 2012 the EPA took final action to approve South Dakota's Regional Haze State Implementation Plan (SIP), finding that South Dakota's SIP submittal met all applicable regional haze regulations. The EPA's final approval of the SIP was effective on May 29, 2012.

On January 14, 2011 OTP filed a petition asking the MPUC for ADP for the design, construction and operation of the BART compliant air quality control system at Big Stone Plant attributable to serving OTP's Minnesota customers. On December 20, 2011 the MPUC granted OTP's petition for ADP for the Big Stone Plant Air Quality Control System (AQCS). The MPUC written order was issued on January 23, 2012.

OTP filed an application for an ADP with the NDPSC on May 20, 2011, and the NDPSC approved OTP's request for an ADP on May 9, 2012.

On March 30, 2012 OTP requested approval from the SDPUC for an Environmental Cost Recovery Rider (ECRR) to recover costs associated with the Big Stone Plant AQCS, with a proposed effective date of October 1, 2012. Information requests for this filing continue and OTP is currently awaiting SDPUC action. This rider is designed to recover the revenue requirements plus carrying charges of the Big Stone AQCS project while under construction as well as after completion of the project until placed into base rates through the filing of a rate case. For the initial period of October 1, 2012 through September 30, 2013, OTP is requesting revenue requirement recovery on expenditures incurred for the Big Stone Plant AQCS. OTP anticipates the effective date of this ECRR will be changed to January 1, 2013.