Otter Tail Corp
Form 10-Q
August 10, 2015

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2015

OR

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

For the transition period from to

Commission file number 0-53713

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

Minnesota	27-0383995
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

215 South Cascade Street, Box 496, Fergus Falls, Minnesota 56538-0496
(Address of principal executive offices) (Zip Code)

866-410-8780
(Registrant's telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

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

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

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

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

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

July 31, 2015 – 37,591,785 Common Shares ($5 par value)

OTTER TAIL CORPORATION

INDEX

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation Consolidated Balance Sheets
(not audited)

(in thousands)	**June 30, 2015**	**December 31, 2014**
Assets		
Current Assets		
Cash and Cash Equivalents	$--	$--
Accounts Receivable:		
Trade—Net	67,315	60,172
Other	18,248	13,179
Inventories	81,803	85,203
Deferred Income Taxes	54,498	49,482
Unbilled Revenues	14,352	17,996
Regulatory Assets	17,736	25,273
Other	8,588	7,187
Assets of Discontinued Operations	133	48,657
Total Current Assets	262,673	307,149
Investments	10,679	8,582
Other Assets	30,827	30,111
Goodwill	31,488	31,488
Other Intangibles—Net	10,863	11,251
Deferred Debits		
Unamortized Debt Expense	3,949	4,300
Regulatory Assets	127,475	129,868
Total Deferred Debits	131,424	134,168
Plant		
Electric Plant in Service	1,583,169	1,545,112
Nonelectric Operations	180,309	175,159
Construction Work in Progress	269,060	248,677
Total Gross Plant	2,032,538	1,968,948

Less Accumulated Depreciation and Amortization	699,113	700,418
Net Plant	1,333,425	1,268,530
Total Assets	$1,811,379	$1,791,279

See accompanying condensed notes to consolidated financial statements.

2

Otter Tail Corporation Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	**June 30, 2015**	**December 31, 2014**
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$43,040	$10,854
Current Maturities of Long-Term Debt	207	201
Accounts Payable	101,020	107,013
Accrued Salaries and Wages	14,077	19,256
Accrued Taxes	9,997	13,793
Derivative Liabilities	14,388	14,230
Other Accrued Liabilities	12,099	8,793
Liabilities of Discontinued Operations	3,260	27,559
Total Current Liabilities	198,088	201,699
Pensions Benefit Liability	93,545	102,711
Other Postretirement Benefits Liability	54,357	53,638
Other Noncurrent Liabilities	24,319	26,794
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	248,581	230,810
Deferred Tax Credits	25,445	26,384
Regulatory Liabilities	77,972	77,013
Other	977	975
Total Deferred Credits	352,975	335,182
Capitalization		
Long-Term Debt, Net of Current Maturities	498,384	498,489
Cumulative Preferred Shares– Authorized 1,500,000 Shares Without Par Value; Outstanding - None	--	--
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, 2015—37,565,590 Shares; 2014—37,218,053 Shares	187,828	186,090
Premium on Common Shares	287,066	278,436
Retained Earnings	119,239	112,903
Accumulated Other Comprehensive Loss	(4,422)	(4,663)
Total Common Equity	589,711	572,766
Total Capitalization	1,088,095	1,071,255
Total Liabilities and Equity	$1,811,379	$1,791,279

See accompanying condensed notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	**Three Months Ended June 30, 2015**	**2014**	**Six Months Ended June 30, 2015**	**2014**
Operating Revenues				
Electric	$90,927	$92,903	$204,460	$211,951
Product Sales	97,226	101,461	186,534	197,379
Total Operating Revenues	188,153	194,364	390,994	409,330
Operating Expenses				
Production Fuel - Electric	4,183	12,603	18,782	34,633
Purchased Power - Electric System Use	19,684	16,476	43,376	38,261
Electric Operation and Maintenance Expenses	37,754	39,774	75,281	74,396
Cost of Products Sold (depreciation included below)	74,986	80,178	146,484	154,117
Other Nonelectric Expenses	8,823	12,722	21,286	22,673
Depreciation and Amortization	14,661	14,472	29,196	28,739
Property Taxes - Electric	3,262	3,387	6,764	6,358
Total Operating Expenses	163,353	179,612	341,169	359,177
Operating Income	24,800	14,752	49,825	50,153
Interest Charges	7,702	7,626	15,445	14,221
Other Income	567	844	1,139	2,379
Income Before Income Taxes—Continuing Operations	17,665	7,970	35,519	38,311
Income Tax Expense—Continuing Operations	4,008	84	8,081	8,646
Net Income from Continuing Operations	13,657	7,886	27,438	29,665
Discontinued Operations				
(Loss) Income - net of Income Tax (Benefit) Expense of ($1,329), $1,402, ($2,705) and $1,177 for the Respective Periods	(1,992)	2,107	(4,064)	1,758
Impairment Loss - net of Income Tax Benefit of $0 for the Six Months ended June 30, 2015	--	--	(1,000)	--
(Loss) Gain on Disposition - net of Income Tax (Benefit) Expense of ($280) and $4,536 for the three and six months ended June 30, 2015	(229)	--	6,997	--
Net (Loss) Income from Discontinued Operations	(2,221)	2,107	1,933	1,758
Net Income	11,436	9,993	29,371	31,423
Average Number of Common Shares Outstanding—Basic	37,433,318	36,409,753	37,338,218	36,325,052
Average Number of Common Shares Outstanding—Diluted	37,653,203	36,652,684	37,558,103	36,568,030
Basic Earnings (Loss) Per Common Share:				

Continuing Operations	$0.37	$0.21	$0.74	$0.82
Discontinued Operations	(0.06)	0.06	0.05	0.05
	$0.31	$0.27	$0.79	$0.87
Diluted Earnings (Loss) Per Common Share:				
Continuing Operations	$0.36	$0.21	$0.73	$0.81
Discontinued Operations	(0.06)	0.06	0.05	0.05
	$0.30	$0.27	$0.78	$0.86
Dividends Declared Per Common Share	$0.3075	$0.3025	$0.6150	$0.6050

See accompanying condensed notes to consolidated financial statements.

4

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in thousands)	**2015**	**2014**	**2015**	**2014**
Net Income	$11,436	$9,993	$29,371	$31,423
Other Comprehensive Income:				
Unrealized Gain on Available-for-Sale Securities:				
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	--	--	(3)	(17)
(Losses) Gains Arising During Period	(37)	36	(5)	19
Income Tax Benefit (Expense)	13	(13)	3	(1)
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	(24)	23	(5)	1
Pension and Postretirement Benefit Plans:				
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 11)	207	51	411	101
Income Tax Expense	(83)	(20)	(165)	(40)
Pension and Postretirement Benefit Plans – net-of-tax	124	31	246	61
Total Other Comprehensive Income	100	54	241	62
Total Comprehensive Income	$11,536	$10,047	$29,612	$31,485

See accompanying condensed notes to consolidated financial statements.

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

(in thousands)	**Six Months Ended June 30, 2015**	**2014**
Cash Flows from Operating Activities		
Net Income	$29,371	$31,423
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net Gain from Sale of Discontinued Operations	(6,997)	--
Net Loss (Income) from Discontinued Operations	5,064	(1,758)
Depreciation and Amortization	29,196	28,739
Deferred Tax Credits	(939)	(907)
Deferred Income Taxes	12,707	13,402
Change in Deferred Debits and Other Assets	11,470	129
Discretionary Contribution to Pension Plan	(10,000)	(20,000)
Change in Noncurrent Liabilities and Deferred Credits	4,025	(936)
Allowance for Equity/Other Funds Used During Construction	(576)	(759)
Change in Derivatives Net of Regulatory Deferral	(123)	95
Stock Compensation Expense—Equity Awards	1,126	736
Other—Net	200	193
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(5,918)	(15,736)
Change in Inventories	3,400	(10,070)
Change in Other Current Assets	1,913	1,523
Change in Payables and Other Current Liabilities	(21,294)	(8,208)
Change in Interest and Income Taxes Receivable/Payable	96	2,664
Net Cash Provided by Continuing Operations	52,721	20,530
Net Cash Used in Discontinued Operations	(10,966)	(16,359)
Net Cash Provided by Operating Activities	41,755	4,171
Cash Flows from Investing Activities		
Capital Expenditures	(83,418)	(79,574)
Net Proceeds from Disposal of Noncurrent Assets	2,628	1,386
Net Increase in Other Investments	(5,763)	(1,639)
Net Cash Used in Investing Activities - Continuing Operations	(86,553)	(79,827)
Net Proceeds from Sale of Discontinued Operations	32,765	--
Net Cash (Used in) Provided by Investing Activities - Discontinued Operations	(1,770)	630
Net Cash Used in Investing Activities	(55,558)	(79,197)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	(947)	2,014
Net Short-Term Borrowings (Repayments)	32,186	(23,051)
Proceeds from Issuance of Common Stock	7,096	8,452
Common Stock Issuance Expenses	(248)	(310)

Payments for Retirement of Capital Stock	(1,421)	(459)
Proceeds from Issuance of Long-Term Debt	--	150,000
Short-Term and Long-Term Debt Issuance Expenses	(4)	(516)
Payments for Retirement of Long-Term Debt	(99)	(40,993)
Dividends Paid and Other Distributions	(23,035)	(22,029)
Net Cash Provided by Financing Activities – Continuing Operations	13,528	73,108
Net Cash Provided by Financing Activities – Discontinued Operations	322	760
Net Cash Provided by Financing Activities	13,850	73,868
Net Change in Cash and Cash Equivalents - Discontinued Operations	(47)	(849)
Net Change in Cash and Cash Equivalents	--	(2,007)
Cash and Cash Equivalents at Beginning of Period	--	2,007
Cash and Cash Equivalents at End of Period	$--	$--

See accompanying condensed notes to consolidated financial statements.

OTTER TAIL CORPORATION

CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated financial statements for the periods presented. The consolidated financial statements and condensed notes thereto should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2014. Because of seasonal and other factors, the earnings for the three and six month periods ended June 30, 2015 should not be taken as an indication of earnings for all or any part of the balance of the year.

The following condensed 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, 2014.

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. Provisions for sales returns 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 (FASB) Accounting Standards Codification (ASC) Topic 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.

Warranty Reserves

Certain products previously sold by the Company carried one to fifteen year warranties. Although the Company engaged 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. The Company's warranty reserve balances as of June 30, 2015 and December 31, 2014 relate entirely to products that were produced by IMD, Inc. and Shrco, Inc. prior to the Company selling the assets of these companies and are included in liabilities of discontinued operations. See note 16 to consolidated financial statements.

Fair Value Measurements

The Company follows ASC Topic 820, *Fair Value Measurements and Disclosures* (ASC 820), 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 (NYMEX).

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 tables present, for each of the hierarchy levels, the Company’s assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2015 and December 31, 2014:

June 30, 2015 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$--	$194
Investments:			
Money Market Deposit Escrow Account – AEV, Inc. and Foley Company Sales	2,500		
Corporate Debt Securities – Held by Captive Insurance Company		6,679	
U.S. Government-Sponsored Enterprises’ Debt Securities – Held by Captive Insurance Company		1,221	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	273		
Total Assets	$2,773	$7,900	$194
Liabilities:			
Derivative Liabilities - Forward Gasoline Purchase Contracts	$--	$219	$--
Derivative Liabilities - Forward Energy Contracts			14,169
Total Liabilities	$--	$219	$14,169

December 31, 2014 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$--	$257
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	120		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		6,761	
U.S. Government-Sponsored Enterprises’ Debt Securities – Held by Captive Insurance Company		1,253	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	593		
Total Assets	$713	$8,014	$257
Liabilities:			
Derivative Liabilities - Forward Gasoline Purchase Contracts	$--	$342	$--
Derivative Liabilities - Forward Energy Contracts			13,888
Total Liabilities	$--	$342	$13,888

The valuation techniques and inputs used for the Level 2 fair value measurements in the table above are as follows:

Forward Gasoline Purchase Contracts – These contracts are priced based on NYMEX quoted prices for Reformulated Blendstock for Oxygenate Blending (RBOB) Gasoline contracts. Prices used for the fair valuation of these contracts are based on NYMEX daily reporting date quoted prices for RBOB contracts with the same settlement periods.

Corporate and U.S. Government-Sponsored Enterprises' Debt Securities Held by the Company's Captive Insurance Company – Fair values are determined on the basis of valuations provided by a third-party pricing service which utilizes industry accepted valuation models and observable market inputs to determine valuation. Some valuations or model inputs used by the pricing service may be based on broker quotes.

Fair values for OTP's forward energy contracts with delivery points that are not at an active trading hub included in Level 3 of the fair value hierarchy in the table above as of June 30, 2015 and December 31, 2014, are based on prices indexed to observable prices at an active trading hub. Prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The June 30, 2015 Level 3 forward electric basis spreads ranged from $3.17 to $7.00 per megawatt-hour under the active trading hub price. The weighted average price was $32.71 per megawatt-hour.

In the table above, the fair value of the Level 3 forward energy contracts in derivative asset and derivative liability positions as of June 30, 2015 are related to power purchase contracts where OTP intends to take or has taken physical delivery of the energy under the contract. When OTP takes physical delivery of the energy purchased under these contracts the costs incurred are subject to recovery in base rates and through fuel clause adjustments. Any derivative assets or liabilities and related gains or losses recorded as a result of the fair valuation of these power purchase contracts will not be realized and are 100% offset by regulatory liabilities and assets related to fuel clause adjustment treatment of purchased power costs. Therefore, the net impact of any recorded fair valuation gains or losses related to these contracts on the Company's consolidated net income is $0 and the net income impact of any future fair valuation adjustments of these contracts will be $0. When energy is delivered under these contracts, they will be settled at the original contract price and any fair valuation gains or losses and related derivative assets or liabilities recorded over the life of the contracts will be reversed along with any offsetting regulatory liabilities or assets. Because of regulatory accounting treatment, any price volatility related to the fair valuation of these contracts had no impact on the Company's reported consolidated net income for the three or six month periods ended June 30, 2015 and 2014.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the six month periods ended June 30, 2015 and 2014:

	Six Months Ended June 30,	
(in thousands)	2015	2014
Forward Energy Contracts - Fair Values Beginning of Period	$(13,631)	$(11,341)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods	4,302	1,161
Net Changes in Fair Value of Contracts Entered into in Prior Periods	(3,732)	7,400
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(13,061)	(2,780)
Net Loss Recognized as Regulatory Assets on Contracts Entered into in Period	(914)	--
Forward Energy Contracts - Net Derivative Liability Fair Values End of Period	$(13,975)	$(2,780)

<u>Inventories</u>

Inventories consist of the following:

(in thousands)	June 30, 2015	December 31, 2014
Finished Goods	$23,276	$ 27,998
Work in Process	10,877	10,628
Raw Material, Fuel and Supplies	47,650	46,577
Total Inventories	$81,803	$ 85,203

Goodwill and Other Intangible Assets

An assessment of the carrying amounts of the goodwill of the Company's reporting units reported under continuing operations as of December 31, 2014 indicated the fair values are in excess of their respective book values and not impaired.

The following table summarizes goodwill by business segment indicating no changes to the carrying amounts in the first six months of 2015:

(in thousands)	Gross Balance December 31, 2014	Accumulated Impairments	Balance (net of impairments) December 31, 2014	Adjustments to Goodwill in 2015	Balance (net of impairments) June 30, 2015
Manufacturing	$ 12,186	$ --	$ 12,186	$ --	$ 12,186
Plastics	19,302	--	19,302	--	19,302
Total	$ 31,488	$ --	$ 31,488	$ --	$ 31,488

9

Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC Topic 360-10-35, *Property, Plant, and Equipment—Overall—Subsequent Measurement*. In the first quarter of 2015, OTP began purchasing emission allowances to apply against sulfur dioxide emissions from its Hoot Lake Plant. The cost of unused emission allowances is included in intangible assets on the Company's June 30, 2015 balance sheets. The following table summarizes the components of the Company's intangible assets at June 30, 2015 and December 31, 2014:

June 30, 2015 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 6,208	$ 10,603	54-154 months
Other Intangible Assets Including Contracts	639	479	160	15 months
Emission Allowances	100	NA	100	Expensed as used
Total	$ 17,550	$ 6,687	$ 10,863	
December 31, 2014 *(in thousands)*				
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 5,784	$ 11,027	60-160 months
Other Intangible Assets Including Contracts	639	415	224	21 months
Total	$ 17,450	$ 6,199	$ 11,251	

The amortization expense for these intangible assets was:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Amortization Expense – Intangible Assets	$ 244	$ 244	$ 488	$ 488

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

(in thousands)	2015	2016	2017	2018	2019
Estimated Amortization Expense – Intangible Assets	$977	$945	$849	$849	$849

The following table presents a reconciliation of OTP's emission allowances balance for the six month period ended June 30, 2015:

(in thousands)	Six Months Ended June 30, 2015
Emission Allowances Beginning Balance	$ --
Allowances Purchased	168
Allowances Used	(68)
Emission Allowances Ending Balance	$ 100

Supplemental Disclosures of Cash Flow Information

(in thousands)	As of June 30, 2015	2014
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions[1]	$31,455	$21,992
Accounts Receivable Outstanding Related to Joint Plant Owner's Share of Capital Additions[2]	$4,188	$4,373

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

[2]*Amounts are deducted from cash used for capital expenditures in subsequent periods when cash is received.*

10

Coyote Station Lignite Supply Agreement – Variable Interest Entity—In October 2012, the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of lignite coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton to be paid by the Coyote Station owners under the LSA will reflect the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining coal to meet the coal fuel supply requirements of Coyote Station from May 2016 through December 2040 and, based on the terms of the LSA, is considered a variable interest entity (VIE) due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal would cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of CCMC as they would be required to buy certain assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of CCMC in that they are required to buy the entity at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. No single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, has the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE and the Company is not required to include CCMC in its consolidated financial statements.

Under the LSA, all development period costs of the Coyote Creek coal mine incurred during the development period will be recovered from the Coyote Station owners over the full term of the production period, which commences with the initial delivery of coal to Coyote Station (anticipated in May 2016), by being included in the cost of production. The development fee and the capital charge incurred during the development period will be recovered from the Coyote Station owners over the first 52 months of the production period by being included in the cost of production during those months. The LSA was amended on March 16, 2015 to provide, among other things, that during any period between December 31, 2016 and any subsequent date on which CCMC makes initial delivery of coal, the Coyote Station owners will pay the following costs of production as advance payments for lignite: depreciation and amortization charges on capital assets and CCMC's obligations under its loans and leases. In addition, if the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) assume, all of CCMC's obligations owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. OTP's 35% share of development period costs, development fees and capital charges incurred by CCMC through June 30, 2015 is $35.9 million. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of June 30, 2015 could be as high as $35.9 million.

New Accounting Standards

ASU 2014-09—In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606) (ASC 606)*. ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

ASU 2014-09 amendments to the ASC are effective for fiscal years beginning after December 15, 2016, however, in July 2015, the FASB voted to approve a one year deferral of the effective date. The deferral permits early adoption, but would not allow adoption any earlier than the original effective date of the standard. Application methods permitted are: (1) full retrospective, (2) retrospective using one or more practical expedients and (3) retrospective with the cumulative effect of initial application recognized at the date of initial application. The Company is currently reviewing ASU 2014-09, identifying key impacts to its businesses, reviewing revenue streams and contracts to determine areas where the amendments in ASU 2014-09 will be applicable and evaluating transition options. The Company does not plan to adopt the updated standards prior to January 1, 2018.

ASU 2015-03—In April 2015, the FASB issued ASU 2015-03, *Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03), which requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. ASU 2015-03 will become effective for interim and annual reporting periods beginning after December 15, 2015 with early adoption permitted. The Company will apply the updated standards in ASU 2015-03 to its consolidated financial statements beginning in the first quarter of 2016. If applied as of June 30, 2015, both the Company's consolidated long-term assets and long-term debt would be reduced by approximately $2.4 million—the balance of its consolidated unamortized debt issuance costs related to its outstanding long-term debt as of June 30, 2015.

ASU 2015-05—In April 2015, the FASB issued ASU 2015-05, *Intangibles—Goodwill and Other—Internal Use Software (Subtopic 350-40): Customers Accounting for Fees Paid in a Cloud Computing Arrangement*, to provide guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. The Company does not expect the adoption of the updated standard to have a material impact on its consolidated financial statements.

ASU 2015-07—In May 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*, which removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. The new standard is effective for reporting periods beginning after December 31, 2016, with early adoption permitted. Once adopted, the update is required to be applied on a retrospective basis for all periods presented. The Company does not expect this new standard to have a material impact on its consolidated financial statements other than the disclosure and presentation of certain investments of the Company's pension plan that are measured using the net asset value practical expedient.

ASU 2015-11—In July 2015, the FASB issued ASU No. 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory,* which requires that inventories be measured at the lower of cost or net realizable value instead of the lower of cost or market value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The standards update is effective prospectively for fiscal years and interim periods beginning after December 15, 2016, with early adoption permitted. The Company does not expect the adoption of the updated standard to have a material impact on its consolidated financial statements.

2. Segment Information

The Company's businesses have been classified into three 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 three segments are: Electric, Manufacturing 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 Midcontinent Independent System Operator, Inc. (MISO) markets. OTP's operations have been the Company's primary business since 1907.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping and fabrication, and production of material and handling trays and horticultural containers. These businesses have manufacturing facilities in Illinois and Minnesota and sell products primarily in the United States.

Plastics consists of businesses producing polyvinyl chloride (PVC) pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the upper Midwest and Southwest regions of the United States.

OTP is a wholly owned subsidiary 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.

No single customer accounted for over 10% of the Company's consolidated revenues in 2014. All of the Company's long-lived assets are within the United States.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
United States of America	97.3 %	95.3 %	96.8 %	96.3 %
Mexico	1.2 %	3.2 %	2.2 %	2.7 %
Canada	1.3 %	1.4 %	1.0 %	0.9 %
All Other Countries (none greater than 0.07%)	0.2 %	0.1 %	0.0 %	0.1 %

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for the three and six months ended June 30, 2015 and 2014 and total assets by business segment as of June 30, 2015 and December 31, 2014 are presented in the following tables:

Operating Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Electric	$90,964	$92,911	$204,511	$211,999
Manufacturing	51,273	53,370	108,032	108,805
Plastics	45,954	48,090	78,506	88,573
Intersegment Eliminations	(38)	(7)	(55)	(47)
Total	$188,153	$194,364	$390,994	$409,330

Interest Charges

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Electric	$ 6,083	$ 6,059	$12,204	$11,138
Manufacturing	846	813	1,678	1,621
Plastics	279	274	525	521
Corporate and Intersegment Eliminations	494	480	1,038	941

Total	$ 7,702	$ 7,626	$ 15,445	$ 14,221

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Electric	$ 1,013	$ (992)	$ 5,234	$ 4,758
Manufacturing	1,157	1,336	1,661	3,007
Plastics	2,689	2,114	3,953	4,247
Corporate	(851)	(2,374)	(2,767)	(3,366)
Total	$ 4,008	$ 84	$ 8,081	$ 8,646

13

Net Income

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Electric	$ 8,252	$ 5,242	$ 21,430	$ 21,895
Manufacturing	1,912	2,300	3,096	5,196
Plastics	4,265	3,433	6,385	6,893
Corporate	(772)	(3,089)	(3,473)	(4,319)
Discontinued Operations	(2,221)	2,107	1,933	1,758
Total	$ 11,436	$ 9,993	$ 29,371	$ 31,423

Identifiable Assets

	June 30,	December 31,
(in thousands)	2015	2014
Electric	$ 1,504,369	$ 1,472,647
Manufacturing	137,735	130,701
Plastics	92,700	87,356
Corporate	76,442	51,918
Assets of Discontinued Operations	133	48,657
Total	$ 1,811,379	$ 1,791,279

3. Rate and Regulatory Matters

Below are descriptions of OTP's major capital expenditure projects and use of reagents and emission allowances that have had, or will have, a significant impact on OTP's revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the Federal Energy Regulatory Commission (FERC), impacting OTP's revenues in 2015 and 2014.

Major Capital Expenditure Projects

Big Stone Plant Air Quality Control System (AQCS)—The South Dakota Department of Environmental and Natural Resources determined the Big Stone Plant is subject to Best-Available Retrofit Technology (BART) requirements of the Clean Air Act, based on air dispersion modeling indicating that Big Stone Plant's emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan.

OTP is currently in the final stages of constructing the BART-compliant AQCS at Big Stone Plant for a current projected cost of approximately $384 million (OTP's 53.9% share would be $207 million) with an expected commercial operation date of December 2015. OTP's share of AQCS construction expenditures incurred through June 30, 2015 is $193.4 million, excluding Allowance for Funds Used During Construction (AFUDC).

Fargo–Monticello 345 kiloVolt (kV) Capacity Expansion 2020 (CapX2020) Project (the Fargo Project)—OTP has invested approximately $80.6 million and has a 13% ownership interest in this 240-mile transmission line. The final phase of this project was energized on April 2, 2015.

Brookings–Southeast Twin Cities 345 kV CapX2020 Project (the Brookings Project)—OTP has invested approximately $25.7 million and has a 4.1% ownership interest in this 250-mile transmission line. The MISO granted unconditional approval of the Brookings Project as a Multi-Value Project (MVP) under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. The final segments of this line were energized on March 26, 2015.

The Big Stone South – Brookings MVP and CapX2020 Project—This is a planned 345 kV transmission line that will extend approximately 70 miles between a proposed substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power –MN (NSP MN) jointly developed this project. 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. The SDPUC approved the certification for the northern portion of the route on April 9, 2013 and granted approval of a route permit for the southern portion of the line on February 18, 2014. On August 1, 2014 OTP and NSP MN entered into agreements to construct the project. This line is expected to be in service in 2017.

The Big Stone South – Ellendale MVP—This is a proposed 345 kV transmission line that will extend 160 to 170 miles between a proposed substation near Big Stone City, South Dakota and a proposed substation near Ellendale, North Dakota. 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. On August 25, 2013 the NDPSC granted Certificates of Public Convenience and Necessity to OTP and MDU for ten miles of the proposed line to be built in North Dakota. On July 10, 2014 the NDPSC approved a Certificate of Corridor Compatibility and a route permit for the North Dakota section of the proposed line. On August 22, 2014 the SDPUC issued an order approving the route permit for the South Dakota section of the proposed line. On June 12, 2015 OTP and MDU entered into agreements to construct the project. This project is expected to be completed in 2019.

Recovery of OTP's transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

Reagent Costs and Emission Allowances

OTP's system wide costs for reagents and Cross-State Air Pollution Rule (CSAPR) emissions allowances are expected to increase to approximately $4.1 million annually through May 2021 when Hoot Lake Plant is expected to be retired, $3.6 million for reagents and $0.5 million for emission allowances. The Minnesota, North Dakota and South Dakota share of costs are approximately 50%, 40% and 10%, respectively. Reagent costs will be phased in during 2015 and 2016 when the Big Stone Plant AQCS and Coyote Station and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) projects are completed and in service. Emissions allowance costs are being incurred during 2015 to maintain compliance with CSAPR rules, which became effective January 1, 2015.

Minnesota

2010 General Rate Case—OTP's most recent general rate increase in Minnesota of approximately $5.0 million, or 1.6%, was granted by the MPUC in an order issued on April 25, 2011 and effective October 1, 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%.

Minnesota Conservation Improvement Programs (MNCIP)—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. On September 26, 2014 the MPUC approved OTP's 2013 financial incentive request for $4.0 million, an updated surcharge rate to be effective October 1, 2014, as well as a change to the carrying charge to be equal to the short term cost of debt set in OTP's most recent general rate case.

Based on results from the 2014 MNCIP program year, OTP estimated a financial incentive for 2014 of $3.0 million in response to the MPUC lowering the MNCIP financial incentive from approximately $0.09 per kwh saved for 2013-2015 to $0.07 per kwh saved for 2014-2016. Additionally, OTP saved approximately 2 million less kwhs in 2014 compared with 2013 under conservation improvement programs in Minnesota. On July 9, 2015 the MPUC granted approval of OTP's 2014 financial incentive of $3.0 million along with an updated surcharge to be effective October 1, 2015.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs, plus a return on investment at the level approved in a utility's last general rate case, of new transmission facilities that meet certain criteria. OTP filed an annual update to its Minnesota TCR rider on February 7, 2013 to include three new projects as well as updated costs associated with existing projects. In a written order issued on March 10, 2014, the MPUC approved OTP's 2013 TCR rider update but disallowed recovery of capitalized internal costs, costs in excess of Certificate of Need estimates and a carrying charge in the TCR rider. These items were removed from OTP's Minnesota TCR rider effective March 1, 2014. OTP will be allowed to seek recovery of these costs in a future rate case. In response to the MPUC's approval of OTP's annual TCR update, OTP submitted a compliance filing in April 2014 reflecting the TCR rider revenue requirements changes relating to the MPUC's ruling and requesting no rate change be implemented at the time. The MPUC approved OTP's compliance filing on June 19, 2014. On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015.

Environmental Cost Recovery (ECR) Rider—On December 18, 2013 the MPUC granted approval of OTP's Minnesota ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant AQCS effective January 1, 2014. The ECR rider recoverable revenue requirements include a current return on the project's CWIP balance at the level approved in OTP's most recent general rate case. OTP filed its 2014 annual update on July 31, 2014, requesting a $4.1 million annual increase in the rider from $6.1 million to $10.2 million. The MPUC approved OTP's ECR rider annual update request on November 24, 2014, effective December 1, 2014. Because the effective date was two months behind the anticipated implementation date for the updated rate and a portion of the requested increase had been collected under the initial rate, the approved updated rate is based on a revenue requirement of $9.8 million. OTP filed its 2015 annual update on July 31, 2015.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On March 12, 2015 the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs will be reviewed in OTP's next general rate case in Minnesota and considered for recovery either through the FCA rider or general rates. These costs are currently being expensed as incurred.

North Dakota

General Rates—OTP's most recent general rate increase in North Dakota of $3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment (NDRRA) which enables OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed with a return on investment at the level approved in OTP's most recent general rate case. On December 28, 2012 OTP submitted an annual update to the NDRRA with a proposed effective date of April 1, 2013. The update resulted in a rate reduction, so the NDPSC did not issue an order suspending the rate change. Consequently, pursuant to statute, OTP was allowed to implement updated rates effective April 1, 2013. On July 10, 2013, the NDPSC approved the updated rates implemented on April 1, 2013. The NDPSC approved OTP's 2013 annual update to the NDRRA on March 12, 2014 with an effective date of April 1, 2014, which resulted in a 13.5% reduction in the NDRRA rate. OTP submitted its 2014 annual update to the NDRRA on December 31, 2014, which was approved by the NDPSC on March 25, 2015 with an effective date of April 1, 2015. In each instance the NDRRA rates have been based upon a return on investment at the rate of return approved in OTP's last general rate case. Approved in the 2014 annual update was a change in rate design from an amount per kwh consumed to a percentage of a customer's bill.

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. For qualifying projects, the law authorizes a current return on construction work in progress and a return on investment at the level approved in the utility's most recent general rate case. On August 30, 2013 OTP filed its annual update to its North Dakota TCR rider rate, which was approved on December 30, 2013 and became effective January 1, 2014. On August 29, 2014 OTP filed its annual update to the North Dakota TCR rider rate. Within this TCR filing, as required by the order for the North Dakota Big Stone II rider, OTP included the over-collection of North Dakota Big Stone II abandoned plant costs of $0.1 million. The NDPSC approved the annual update on December 17, 2014 with an effective date of January 1, 2015.

Environmental Cost Recovery Rider—On May 9, 2012 the NDPSC approved OTP’s application for an Advance Determination of Prudence related to the Big Stone Plant AQCS. On February 8, 2013 OTP filed a request with the NDPSC for an ECR rider to recover OTP’s North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS. On December 18, 2013 the NDPSC approved OTP’s North Dakota ECR rider based on revenue requirements through the 2013 calendar year and thereafter, with rates effective for bills rendered on or after January 1, 2014. The ECR provides for a current return on construction work in progress and a return on investment at the level approved in OTP’s most recent general rate case. On March 31, 2014 OTP filed an annual update to its North Dakota ECR rider rate. The update included a request to increase the ECR rider rate from 4.319% of base rates to 7.531% of base rates. The NDPSC approved OTP’s 2014 ECR rider annual update request on July 10, 2014 with an August 1, 2014 implementation date. On March 31, 2015 OTP filed its annual update to the ECR. In this annual update, OTP updated the revenue requirements for the Big Stone Plant AQCS project and it proposed ECR recovery for the Hoot Lake Plant MATS project costs. The most recent update included a request to increase the ECR rider rate from 7.531% of base rates to 9.193% of base rates. The NDPSC approved the annual update on June 17, 2015 with an effective date of July 1, 2015.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the NDPSC to revise its FCA rider in North Dakota to include recovery of new reagent and emission allowance costs. On February 25, 2015 the NDPSC approved recovery of these costs through modification of the ECR rider, instead of recovery through the FCA as OTP had proposed. The ECR rider reagent and emissions allowance charge became effective May 1, 2015.

South Dakota

2010 General Rate Case—On April 21, 2011, the SDPUC issued a written order approving an overall revenue increase for OTP of approximately $643,000 (2.32%) and an overall rate of return on rate base of 8.50%. 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. The SDPUC approved an annual update to OTP’s South Dakota TCR on April 23, 2013 with an effective date of May 1, 2013. The SDPUC approved OTP’s following annual update on February 18, 2014 with an effective date of March 1, 2014. The SDPUC approved OTP’s most recent annual update on February 13, 2015 with an effective date of March 1, 2015.

Environmental Cost Recovery Rider—On November 25, 2014 the SDPUC approved OTP’s ECR rider request to recover OTP’s jurisdictional share of costs and provide a return on investment for the Big Stone Plant AQCS and Hoot Lake Plant MATS projects, with an effective date of December 1, 2014.

Reagent Costs and Emission Allowances—On August 1, 2014 OTP filed a request with the SDPUC to revise its FCA rider in South Dakota to include recovery of reagent and emission allowance costs. On September 16, 2014 the SDPUC approved OTP's request to include recovery of these costs in its South Dakota FCA rider.

Revenues Recorded under Rate Riders

The following table presents revenue recorded by OTP under rate riders in place in Minnesota, North Dakota and South Dakota for the three and six month periods ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
Rate Rider *(in thousands)*	2015	2014	2015	2014
Minnesota				
Conservation Improvement Program Costs and Incentives[1]	$ 1,610	$ 1,471	$ 3,538	$ 2,992
Transmission Cost Recovery	1,212	1,776	2,827	4,080
Environmental Cost Recovery	2,600	1,703	5,157	3,466
North Dakota				
Renewable Resource Adjustment	1,942	2,013	3,825	3,448
Transmission Cost Recovery	1,411	1,707	3,347	3,221
Environmental Cost Recovery	2,765	1,452	4,921	2,974
Big Stone II Project Costs	--	--	--	361
South Dakota				
Transmission Cost Recovery	281	364	644	710
Environmental Cost Recovery	519	--	1,023	--

[1]*Includes MNCIP costs recovered in base rates.*

17

FERC

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. 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 the FERC reaffirmed the MVP cost allocation on rehearing.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the return on equity (ROE) component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants are seeking to reduce the current 12.38% return on equity used in MISO's transmission rates to a proposed 9.15%. A group of MISO transmission owners have filed responses to the complaint, defending the current return on equity and seeking dismissal of the complaint. On October 16, 2014 the FERC issued an order finding that the current MISO return on equity may be unjust and unreasonable and setting the issue for hearing, subject to the outcome of settlement discussion. Settlement discussions did not resolve the dispute and the FERC set the proceeding to a Track II Hearing to begin August 17, 2015 for complex cases that can take several months to decide with a FERC decision anticipated in fall 2016 at the earliest. On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the resolution of the return on equity complaint proceeding.

On February 12, 2015 another group of stakeholders filed a complaint with the FERC seeking to reduce the return on equity component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff from the current 12.38% to a proposed 8.67%. A group of MISO transmission owners have filed responses to the complaint, defending the current return on equity and seeking dismissal of the complaint. The FERC issued an order on June 18, 2015 setting the complaint for hearing to begin on February 16, 2016. A FERC decision is not expected until 2017.

OTP recorded reductions in revenue of $0.6 million in the first quarter of 2015 and $0.2 million in the second quarter of 2015 and has a $0.8 million liability as of June 30, 2015 representing its best estimate of a refund obligation, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a potential reduction by FERC in the ROE component of the MISO Tariff.

4. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC Topic 980, *Regulated Operations* (ASC 980). 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. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives. The following tables indicate the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

	June 30, 2015			Remaining Recovery/
(in thousands)	Current	Long-Term	Total	Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$7,464	$97,840	$105,304	see below
Deferred Marked-to-Market Losses[1]	2,098	12,071	14,169	66 months
Conservation Improvement Program Costs and Incentives[2]	2,550	4,065	6,615	24 months
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	5,421	5,421	asset lives
Big Stone II Unrecovered Project Costs – Minnesota[1]	610	2,963	3,573	90 months
Minnesota Transmission Cost Recovery Rider Accrued Revenues[2]	2,153	950	3,103	24 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	1,642	475	2,117	24 months
Debt Reacquisition Premiums[1]	351	1,715	2,066	207 months
Deferred Income Taxes[1]	--	835	835	asset lives
Big Stone II Unrecovered Project Costs – South Dakota[2]	100	693	793	95 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	594	--	594	12 months
North Dakota Renewable Resource Rider Accrued Revenues[2]	--	379	379	21 months
North Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	174	--	174	12 months
Minnesota Renewable Resource Rider Accrued Revenues[2]	--	68	68	see below
Total Regulatory Assets	$17,736	$127,475	$145,211	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$75,355	$75,355	asset lives
Refundable Fuel Clause Adjustment Revenues	2,605	--	2,605	12 months
Deferred Income Taxes	--	1,346	1,346	asset lives
North Dakota Renewable Resource Rider Accrued Refund	1,333	--	1,333	12 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	--	1,031	1,031	see below
Minnesota Environmental Cost Recovery Rider Accrued Refund	391	--	391	12 months
Deferred Marked-to-Market Gains	51	143	194	31 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	97	103	222 months

Big Stone II Over Recovered Project Costs – North Dakota	74	--	74	6 months
South Dakota Environmental Cost Recovery Rider Accrued Refund	40	--	40	12 months
South Dakota Transmission Cost Recovery Rider Accrued Refund	30	--	30	12 months
Total Regulatory Liabilities	$4,530	$77,972	$82,502	
Net Regulatory Asset Position	$13,206	$49,503	$62,709	

[1] *Costs subject to recovery without a rate of return.*

[2] *Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.*

(in thousands)	December 31, 2014 Current	Long-Term	Total	Remaining Recovery/ Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$7,464	$ 101,526	$ 108,990	see below
Deferred Marked-to-Market Losses[1]	4,492	9,396	13,888	72 months
Conservation Improvement Program Costs and Incentives[2]	5,843	2,500	8,343	18 months
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	5,190	5,190	asset lives
Big Stone II Unrecovered Project Costs – Minnesota[1]	592	3,207	3,799	96 months
Minnesota Transmission Cost Recovery Rider Accrued Revenues[2]	943	2,455	3,398	24 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	2,585	807	3,392	24 months
Debt Reacquisition Premiums[1]	351	1,890	2,241	213 months
Deferred Income Taxes[1]	--	2,086	2,086	asset lives
Recoverable Fuel and Purchased Power Costs[1]	1,114	--	1,114	12 months
North Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	859	--	859	12 months
Big Stone II Unrecovered Project Costs – South Dakota[2]	100	743	843	101 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	706	--	706	12 months
Minnesota Environmental Cost Recovery Rider Accrued Revenues[2]	186	--	186	12 months
Minnesota Renewable Resource Rider Accrued Revenues[2]	--	68	68	see below
South Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	38	--	38	12 months
Total Regulatory Assets	$25,273	$ 129,868	$ 155,141	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$ 74,237	$ 74,237	asset lives
Deferred Income Taxes	--	1,550	1,550	asset lives
North Dakota Renewable Resource Rider Accrued Refund	933	85	1,018	15 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	--	784	784	see below
Deferred Marked-to-Market Gains	--	257	257	67 months
Big Stone II Over Recovered Project Costs – North Dakota	147	--	147	12 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	100	106	228 months
South Dakota Transmission Cost Recovery Rider Accrued Refund	48	--	48	12 months
South Dakota – Nonasset-Based Margin Sharing Excess	24	--	24	12 months
Total Regulatory Liabilities	$1,158	$ 77,013	$ 78,171	
Net Regulatory Asset Position	$24,115	$ 52,855	$ 76,970	

[1]*Costs subject to recovery*

without a rate of return.

[2]*Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.*

The regulatory asset related to prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC Topic 715, *Compensation—Retirement Benefits*, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

All Deferred Marked-to-Market Gains and Losses recorded as of June 30, 2015 are related to forward purchases of energy scheduled for delivery through December 2020.

Conservation Improvement Program Costs and Incentives represent mandated conservation expenditures and incentives recoverable through retail electric rates.

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

Big Stone II Unrecovered Project Costs – Minnesota are the Minnesota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II generation project.

Minnesota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to Minnesota customers as of June 30, 2015.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-up relates to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-up also includes the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 207 months.

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

Big Stone II Unrecovered Project Costs – South Dakota are the South Dakota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II generation project.

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the North Dakota share of amounts invested in the construction of the Big Stone Plant AQCS project and Hoot Lake Plant MATS project costs, net of amounts billed under the rider.

North Dakota Renewable Resource Rider Accrued Revenues relate to qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of June 30, 2015.

North Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to North Dakota customers as of June 30, 2015.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers. On April 4, 2013 the MPUC approved OTP’s request to set the MNRRA rate to zero effective May 1, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered in OTP’s next general rate case.

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

The North Dakota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of June 30, 2015.

Revenue for Rate Case Expenses Subject to Refund – Minnesota relate to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund.

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are refundable to Minnesota customers as of June 30, 2015.

Big Stone II Over Recovered Project Costs – North Dakota represent amounts collected from North Dakota customers in excess of the North Dakota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II generation project.

The South Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the South Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to South Dakota customers as of June 30, 2015.

The South Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers that are refundable to South Dakota customers as of June 30, 2015.

If for any reason, OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an expense or income item in the period in which the application of guidance under ASC 980 ceases.

5. Forward Contracts Classified as Derivatives

Electricity Contracts

All of OTP's wholesale purchases and sales of energy under forward contracts that do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. OTP's objective in entering into forward contracts for the purchase and sale of energy is to meet the energy requirements of its retail customers and to optimize the use of its generating and transmission facilities. 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. Prior to December 2014, OTP also entered into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales. Effective December 31, 2014 OTP discontinued its trading activities not directly associated with serving retail customers.

OTP's forward contracts outstanding as of June 30, 2015 and December 31, 2014 for the purchase of electricity are scheduled for delivery at the OTP node, which is an illiquid trading point. Prices used to value OTP's forward purchases at this trading point were based on a basis spread between the OTP node and more liquid trading hub prices. These basis spreads were determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into Level 3 of the fair value hierarchy set forth in ASC 820.

The following tables show the effect of marking to market OTP's forward contracts for the purchase of electricity and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of June 30, 2015 and December 31, 2014, and the change in the Company's consolidated balance sheet position from December 31, 2014 to June 30, 2015 and December 31, 2013 to June 30, 2014:

(in thousands)	June 30, 2015	December 31, 2014
Current Asset – Marked-to-Market Gain	$194	$257
Regulatory Asset – Current Deferred Marked-to-Market Loss	2,098	4,492
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	12,071	9,396
Total Assets	14,363	14,145
Current Liability – Marked-to-Market Loss	(14,169)	(13,888)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(51)	--
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(143)	(257)
Total Liabilities	(14,363)	(14,145)
Net Fair Value of Marked-to-Market Energy Contracts	$--	$--

(in thousands)	Year-to-Date June 30,	Year-to-Date June 30,

	2015	2014
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Year	$ --	$ 115
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	--	(72)
Changes in Fair Value of Contracts Entered into in Prior Periods	--	(43)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	--
Changes in Fair Value of Contracts Entered into in Current Period	--	--
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ --	$ --

The following realized and unrealized net losses on forward energy contracts are included in electric operating revenues on the Company’s consolidated statements of income:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Net Losses on Forward Electric Energy Contracts	$--	$(9)	$--	$(13)

OTP has 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. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor’s), Baa3 (Moody’s) or BBB- (Fitch). OTP had no exposure at June 30, 2015 to counterparties with investment grade or below investment grade credit ratings with respect to any of its forward energy contracts.

Individual counterparty exposures for certain contracts can be offset according to legally enforceable netting arrangements. However, the Company does not net offsetting payables and receivables or derivative assets and liabilities under legally enforceable netting arrangements on the face of its consolidated balance sheet. The amounts of derivative asset and derivative liability balances that were subject to legally enforceable netting arrangements as of June 30, 2015 and December 31, 2014 are indicated in the following table:

(in thousands)	June 30, 2015	December 31, 2014
Derivative assets subject to legally enforceable netting arrangements	$194	$257
Derivative liabilities subject to legally enforceable netting arrangements	(14,388)	(14,230)
Net balance subject to legally enforceable netting arrangements	$(14,194)	$(13,973)

The following table provides a breakdown of OTP's credit risk standing on forward energy contracts in marked-to-market loss positions as of June 30, 2015 and December 31, 2014:

Current Liability – Marked-to-Market Loss *(in thousands)*	June 30, 2015	December 31, 2014
Loss Contracts Covered by Deposited Funds or Letters of Credit	$219	$45
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade[1]	14,169	13,888
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	297
Total Current Liability – Marked-to-Market Loss	$14,388	$14,230
[1]*Certain OTP 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 the immediate deposit of cash to cover contracts in net liability positions.*		
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade	*$14,169*	*$13,888*
Offsetting Gains with Counterparties under Master Netting Agreements	*(194)*	*(257)*
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	*$13,975*	*$13,631*

6. Reconciliation of Common Shareholders' Equity, Common Shares and Earnings Per Share

<u>Reconciliation of Common Shareholders' Equity</u>

(in thousands)	Par Value, Common Shares	Premium on Common	Retained Earnings	Accumulated Other Comprehensive	Total Common Equity

		Shares		Income/(Loss)	
Balance, December 31, 2014	$186,090	$278,436	$112,903	$ (4,663)	$572,766
Common Stock Issuances, Net of Expenses	1,962	8,673			10,635
Common Stock Retirements	(224)	(1,197)			(1,421)
Net Income			29,371		29,371
Other Comprehensive Income				241	241
Tax Benefit – Stock Compensation		28			28
Employee Stock Incentive Plans Expense		1,126			1,126
Common Dividends ($0.615 per share)			(23,035)		(23,035)
Balance, June 30, 2015	$187,828	$287,066	$119,239	$ (4,422)	$589,711

Shelf Registration

On May 11, 2015, the Company filed a shelf registration statement with the U.S. Securities and Exchange Commission (SEC) under which the Company may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, including common shares of the Company. On May 11, 2015, the Company entered into a Distribution Agreement with J.P. Morgan Securities (JPMS) under which it may offer and sell its common shares from time to time in an At-the-Market offering program through JPMS, as its distribution agent, up to an aggregate sales price of $75 million.

Common Shares

Following is a reconciliation of the Company's common shares outstanding from December 31, 2014 through June 30, 2015:

Common Shares Outstanding, December 31, 2014	37,218,053
Issuances:	
Automatic Dividend Reinvestment and Share Purchase Plan:	
Dividends Reinvested	93,855
Cash Invested	43,724
Executive Stock Performance Awards (for 2012 grants)	89,991
At-the-Market Offering	38,160
Directors Deferred Compensation	36,828
Employee Stock Purchase Plan:	
Cash Invested	19,993
Dividends Reinvested	13,036
Employee Stock Ownership Plan	21,137
Restricted Stock Issued to Directors	15,200
Stock Options Exercised	10,250
Vesting of Restricted Stock Units	10,200
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(44,837)
Common Shares Outstanding, June 30, 2015	37,565,590

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income for the three and six month periods ended June 30, 2015 and 2014. The denominator used in the calculation of basic earnings per common share is the weighted average number of common shares outstanding during the period excluding nonvested restricted shares granted to the Company's directors and employees, which are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. The denominator used in the calculation of diluted earnings per common share is derived by adjusting basic shares outstanding for the items listed in the following reconciliation of Weighted Average Common Shares Outstanding – Basic to Weighted Average Common Shares Outstanding – Diluted for the following periods:

	Three Months ended June 30		Six Months ended June 30	
	2015	2014	2015	2014
Weighted Average Common Shares Outstanding – Basic	37,433,318	36,409,753	37,338,218	36,325,052
Plus:				
Shares Expected to be Awarded for Stock Performance Awards Granted to Executive Officers	235,900	225,800	235,900	225,800
Nonvested Restricted Shares	51,798	90,110	51,798	90,110

Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	75,100	47,650	75,100	47,650
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	3,676	39,257	3,676	39,257
Potentially Dilutive Stock Options	--	14,400	--	14,400
Less:				
Shares Equivalent of Tax Savings from Issuance of Dilutive Shares	(146,589)	(161,954)	(146,589)	(161,986)
Shares Equivalent of Proceeds from Exercise of Potentially Dilutive Stock Options	--	(12,332)	--	(12,253)
Total Dilutive Shares	219,885	242,931	219,885	242,978
Weighted Average Common Shares Outstanding – Diluted	37,653,203	36,652,684	37,558,103	36,568,030

The effect of dilutive shares on earnings per share for the three and six month periods ended June 30, 2015 and 2014, resulted in no differences greater than $0.01 between basic and diluted earnings per share in total or from continuing or discontinued operations in any period.

7. Share-Based Payments

Stock Incentive Awards

On February 6, 2015 and April 13, 2015 the Company's Board of Directors granted the following stock incentive awards to the Company's executive officers under the 2014 Stock Incentive Plan.

Award	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
Stock Performance Awards Granted to Executive Officers	84,300	$ 26.99	December 31, 2017
Restricted Stock Units Granted to Executive Officers:			
Graded Vesting	22,700	$ 31.68	25% per year through February 6, 2019
Cliff Vesting	6,400	$ 31.675	100% on February 6, 2020

On April 13, 2015 the Company's Board of Directors granted the following stock incentive awards to the Company's non-employee directors and key employees under the 2014 Stock Incentive Plan:

Award	Shares/Units Granted	Grant-Date Fair Value per Award	Vesting
Restricted Stock Granted to Nonemployee Directors	15,200	$ 31.775	25% per year through April 8, 2019
Restricted Stock Units Granted to Key Employees	11,900	$ 27.05	100% on April 8, 2019

Under the performance share award agreements the aggregate award for performance at target is 84,300 shares. For target performance the Company's executive officers would earn an aggregate of 56,200 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 measurement period of January 1, 2015 through December 31, 2017. The Company's executive officers would also earn an aggregate of 28,100 common shares for achieving the target set for the Company's 3-year average adjusted return on equity. Actual payment may range from zero to 150% of the target amount, or up to 126,450 common shares. 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 Topic 718, *Compensation–Stock Compensation,* 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.

Under the 2015 performance award agreements, payment and the amount of payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to certain officers who are parties to executive employment agreements with the Company is to be made at the target amount at the date of any such event.

The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement or, subject to proration in certain cases. All restricted stock units granted to executive officers are eligible to receive dividend equivalent payments on all unvested awards over the awards respective vesting periods, subject to forfeiture under the terms of the restricted stock unit award agreements. The restricted shares granted to the Company’s nonemployee directors are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreements. The grant-date fair value of each restricted stock unit granted to executive officers and of each share of restricted stock granted to nonemployee directors was the average of the high and low market price per share on the dates of grant. The grant date fair value of each restricted stock unit granted to a key employee that is not an executive officer of the Company was based on the market value of one share of the Company’s common stock on the date of grant, discounted for the value of the dividend exclusion on those restricted stock units over the four-year vesting period. Under the terms of the restricted stock unit award agreements, all outstanding (unvested) restricted stock units held by a retiring grantee vest immediately on normal retirement.

As of June 30, 2015 the remaining unrecognized compensation expense related to outstanding, unvested stock-based compensation was approximately $4.2 million (before income taxes) which will be amortized over a weighted-average period of 2.7 years.

Amounts of compensation expense recognized under the Company's six stock-based payment programs for the three and six month periods ended June 30, 2015 and 2014 are presented in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Employee Stock Purchase Plan (15% discount)	$ 45	$ 45	$ 94	$ 87
Restricted Stock Granted to Directors	106	98	204	221
Restricted Stock Granted to Executive Officers	144	207	301	342
Restricted Stock Units Granted to Nonexecutive Employees	81	28	147	86
Restricted Stock Units Granted to Executive Officers	127	--	380	--
Stock Performance Awards Granted to Executive Officers	37	518	1,057	1,044
Totals	$ 540	$ 896	$ 2,183	$ 1,780

8. Retained Earnings Restriction

The Company is a holding company with no significant operations of its own. The primary source of funds for payments of dividends to the Company's shareholders is from dividends paid or distributions made by the Company's subsidiaries. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by the Company's subsidiaries.

Both the Company and OTP credit agreements contain restrictions on the payment of cash dividends on a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of June 30, 2015 the Company was in compliance with the debt covenants. See note 10 to the Company's consolidated financial statements on Form 10-K for the year ended December 31, 2014 for further information on the covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to the Company by requiring an equity-to-total-capitalization ratio between 46.9% and 57.3%. OTP's equity to total capitalization ratio including short-term debt was 52.1% as of June 30, 2015. Total capitalization for OTP cannot currently exceed $1,056,300,000.

9. Commitments and Contingencies

Construction and Other Purchase Commitments

At December 31, 2014 OTP had commitments under contracts in connection with construction programs extending into 2018 of approximately $106.6 million. At June 30, 2015 OTP had commitments under contracts in connection with construction programs extending into 2018 aggregating approximately $94.3 million.

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2039. In June 2015, OTP entered into energy purchase agreements for the purchase of electricity in July of 2015 to make up for reduced generation at Big Stone Plant and Coyote Station. A scheduled maintenance outage at Big Stone Plant was extended through the beginning of August 2015 due to unanticipated turbine repairs. Coyote Station continues to make repairs related to damage caused by a boiler feed pump failure and ensuing fire that occurred in December 2014. The total cost for the replacement power was approximately $4.0 million.

OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements, under which OTP is committed to the minimum purchase amounts or to make payments in lieu thereof, expire in 2015, 2016, 2017 and 2040. In the first quarter of 2015, OTP entered into a second contract for the purchase of Wyoming subbituminous coal to meet a portion of its 2015 through 2017 coal requirements at Big Stone Plant. OTP's share of the purchase commitment under this contract as of June 30, 2015 was approximately $10.0 million. Fuel clause adjustment mechanisms lessen the risk of loss from market price changes because they provide for recovery of most fuel costs.

Operating Leases

In April of 2015, OTP entered into an agreement to extend the term of its lease of rail cars used for the transport of coal to Hoot Lake Plant by 36 months beginning April 1, 2015. The remaining commitment under this contract as of June 30, 2015 was approximately $2.6 million.

Contingencies

Contingencies, by their nature, relate to uncertainties that require the Company's management to exercise judgment both in assessing the likelihood a liability has been incurred as well as in estimating the amount of potential loss. The most significant contingencies impacting the Company's consolidated financial statements are those related to environmental remediation, risks associated with indemnification obligations under divestitures of discontinued operations and litigation matters. Should all of these known items result in liabilities being incurred, the loss could be as high as $2.7 million.

OTP recorded reductions in revenue of $0.6 million in the first quarter of 2015 and $0.2 million in the second quarter of 2015 and has a $0.8 million liability as of June 30, 2015 representing its best estimate of a refund obligation, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a potential reduction by FERC in the ROE component of the MISO Tariff.

On December 19, 2014, the EPA announced a rule regulating coal combustion residuals (CCR) as a non-hazardous solid waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule was published on April 17, 2015, which triggered a 90-day period within which petitions for judicial review could be filed. Before the challenge period expired on July 16, 2015, several parties filed petitions for judicial review in the United States Court of Appeals for the District of Columbia Circuit. The United States House of Representatives also passed a bill on July 22, 2015, to delay the effective date of certain portions of the CCR rule (the regulation of CCR under Subtitle D of RCRA). The bill would also eliminate some portions of the CCR rule, such as restrictions on how close existing CCR containment sites may be to the uppermost aquifer. The bill would also authorize states to enforce CCR standards, using the federal rule as minimum standards. Finally, the bill would prohibit the EPA from regulating CCR as a hazardous waste under Subtitle C of RCRA. The United States Senate is considering a similar bill. The Obama Administration has threatened to veto legislation designed to alter the CCR rule. The outcome of these judicial challenges and legislative actions cannot be predicted. Thus, uncertainty regarding the status of the CCR rule is likely to continue for a period of time.

The CCR rule requires OTP to complete certain actions, such as installing additional groundwater monitoring wells and investigating whether existing surface impoundments meet defined location restrictions, in order to determine whether existing surface impoundments should be retired or retrofitted with liners. Existing landfill cells can continue to operate as designed, but future expansions will require composite liner and leachate collection systems.

In the second quarter of 2015, subsequent to the publishing of the CCR rule, OTP completed an assessment of its ash handling and storage facilities at Hoot Lake Plant, Coyote Station and Big Stone Plant and determined that it has no immediate obligation under the rules to close or modify any existing ash handling facilities or storage sites but is likely to discontinue the use of one pit at Coyote Station to avoid the potential for future obligations related to this site under the CCR rule. Additionally, OTP has identified a slag sluice pond and slag stockpile area at Big Stone Plant that will need to be reclaimed at a future date to comply with the CCR rule. OTP established an ARO liability of approximately $0.5 million for its share of the estimated future costs to reclaim this site. Although identified as a new ARO resulting from the issuance of the CCR rule, the costs to reclaim the area have always been included in Big Stone Plant's estimated removal costs currently being recovered as a component of depreciation expense. Therefore, the establishment of the ARO will have no impact on current year consolidated operating expenses but will result in an offsetting charge to the removal cost component of the accumulated provision for depreciation on the Company's consolidated balance sheet. Future reclamation costs, when incurred, will be charged against, and reduce, the accumulated ARO liability.

Other

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of June 30, 2015 will not be material.

10. Short-Term and Long-Term Borrowings

The following table presents the status of our lines of credit as of June 30, 2015 and December 31, 2014:

(in thousands)	Line Limit	In Use on June 30, 2015	Restricted due to Outstanding Letters of Credit	Available on June 30, 2015	Available on December 31, 2014
Otter Tail Corporation Credit Agreement	$ 150,000	$ 38,494	$ 150	$ 111,356	$ 138,872
OTP Credit Agreement	170,000	4,546	310	165,144	169,440
Total	$ 320,000	$ 43,040	$ 460	$ 276,500	$ 308,312

The following tables provide a breakdown of the assignment of the Company’s consolidated short-term and long-term debt outstanding as of June 30, 2015 and December 31, 2014:

June 30, 2015 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$4,546	$ 38,494	$ 43,040
Long-Term Debt:			
9.000% Notes, due December 15, 2016		$ 52,330	52,330
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000		33,000
Senior Unsecured Notes 4.63%, due December 1, 2021	140,000		140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000		30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000		42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	60,000		60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000		50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000		90,000
North Dakota Development Note, 3.95%, due April 1, 2018	--	219	219
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	--	1,042	1,042
Total	$445,000	$ 53,591	$ 498,591
Less: Current Maturities	--	207	207
Total Long-Term Debt	$445,000	$ 53,384	$ 498,384
Total Short-Term and Long-Term Debt (with current maturities)	$449,546	$ 92,085	$ 541,631

December 31, 2014 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation

			Consolidated
Short-Term Debt	$ --	$ 10,854	$ 10,854
Long-Term Debt:			
9.000% Notes, due December 15, 2016		$ 52,330	$ 52,330
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	$ 33,000		33,000
Senior Unsecured Notes 4.63%, due December 1, 2021	140,000		140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000		30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000		42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	60,000		60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000		50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000		90,000
North Dakota Development Note, 3.95%, due April 1, 2018	--	256	256
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	--	1,105	1,105
Total	$ 445,000	$ 53,691	$ 498,691
Less: Current Maturities	--	201	201
Unamortized Debt Discount	--	1	1
Total Long-Term Debt	$ 445,000	$ 53,489	$ 498,489
Total Short-Term and Long-Term Debt (with current maturities)	$ 445,000	$ 64,544	$ 509,544

28

11. Pension Plan and Other Postretirement Benefits

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Service Cost—Benefit Earned During the Period	$1,530	$1,174	$3,030	$2,349
Interest Cost on Projected Benefit Obligation	3,347	3,285	6,672	6,570
Expected Return on Assets	(4,592)	(4,186)	(9,192)	(8,373)
Amortization of Prior-Service Cost:				
From Regulatory Asset	47	65	94	129
From Other Comprehensive Income*1*	1	1	2	3
Amortization of Net Actuarial Loss:				
From Regulatory Asset	1,705	868	3,338	1,736
From Other Comprehensive Income*1*	46	23	86	46
Net Periodic Pension Cost	$2,084	$1,230	$4,030	$2,460

1Corporate cost included in Other Nonelectric Expenses.

Cash flows—The Company made discretionary plan contributions totaling $10,000,000 in January 2015. The Company currently is not required and does not expect to make an additional contribution to the plan in 2015. The Company also made discretionary plan contributions totaling $20,000,000 in January 2014.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Service Cost—Benefit Earned During the Period	$47	$12	$94	$25
Interest Cost on Projected Benefit Obligation	381	380	762	760
Amortization of Prior-Service Cost:				
From Regulatory Asset	4	6	8	11
From Other Comprehensive Income*1*	9	13	19	26

Amortization of Net Actuarial Loss:				
From Regulatory Asset	84	36	167	71
From Other Comprehensive Income*2*	150	11	301	23
Net Periodic Pension Cost	$675	$458	$1,351	$916
1Amortization of Prior Service Costs from Other Comprehensive Income Charged to:				
Electric Operation and Maintenance Expenses	*$4*	*$5*	*$8*	*$10*
Other Nonelectric Expenses	*5*	*8*	*11*	*16*
2Amortization of Net Actuarial Loss from Other Comprehensive Income Charged to:				
Electric Operation and Maintenance Expenses	*$77*	*$33*	*$155*	*$66*
Other Nonelectric Expenses	*73*	*(22)*	*146*	*(43)*

Postretirement Benefits—Components of net periodic postretirement benefit cost for health insurance and life insurance benefits for retired OTP and corporate employees, net of the effect of Medicare Part D Subsidy:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Service Cost—Benefit Earned During the Period	$273	$213	$648	$528
Interest Cost on Projected Benefit Obligation	499	542	1,049	1,100
Amortization of Prior-Service Cost:				
From Regulatory Asset	51	51	102	102
From Other Comprehensive Income[1]	2	2	3	3
Amortization of Net Actuarial Loss:				
From Regulatory Asset	(48)	--	--	--
From Other Comprehensive Income[1]	(1)	--	--	--
Net Periodic Postretirement Benefit Cost	$776	$808	$1,802	$1,733
Effect of Medicare Part D Subsidy	$(293)	$(166)	$(743)	$(474)

[1]Corporate cost included in Other Nonelectric Expenses.

12. Fair Value of Financial Instruments

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

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balances outstanding as of June 30, 2015 and December 31, 2014 related to the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were subject to variable interest rates of LIBOR plus 1.75% and LIBOR plus 1.25%, respectively, which approximate market rates.

Long-Term Debt including Current Maturities—The fair value of the Company's and OTP's long-term debt is estimated based on the current market indications of rates available to the Company for the issuance of debt. The Company's long-term debt subject to variable interest rates approximates fair value. The fair value measurements of the Company's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820.

	June 30, 2015		December 31, 2014	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Short-Term Debt	$(43,040)	$(43,040)	$(10,854)	$(10,854)

Long-Term Debt including Current Maturities	(498,591)	(554,434)	(498,690)	(600,828)

30

14. Income Tax Expense – Continuing Operations

The following table provides a reconciliation of income tax expense calculated at the net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on the Company’s consolidated statements of income for the three and six month periods ended June 30, 2015 and 2014:

(in thousands)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Income Before Income Taxes – Continuing Operations	$17,665	$7,970	$35,519	$38,311
Tax Computed at Company’s Net Composite Federal and State Statutory Rate (39%)	6,889	3,108	13,852	14,941
Increases (Decreases) in Tax from:				
Federal Production Tax Credits (PTCs)	(1,656)	(1,864)	(3,710)	(4,116)
Section 199 Domestic Production Activities Deduction	(363)	(349)	(725)	(707)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(213)	(212)	(425)	(425)
Employee Stock Ownership Plan Dividend Deduction	(171)	(189)	(343)	(379)
Investment Tax Credits	(143)	(127)	(286)	(254)
AFUDC Equity	(125)	(164)	(225)	(297)
Other Items – Net	(210)	(119)	(57)	(117)
Income Tax Expense – Continuing Operations	$4,008	$84	$8,081	$8,646
Effective Income Tax Rate – Continuing Operations	22.7 %	1.1 %	22.8 %	22.6 %

The following table summarizes the activity related to our unrecognized tax benefits:

(in thousands)	2015	2014
Balance on January 1	$222	$4,239
Increases Related to Tax Positions for Prior Years	--	137
Increases Related to Tax Positions for Current Year	86	--
Uncertain Positions Resolved During Year	--	--
Balance on June 30	$308	$4,376

The balance of unrecognized tax benefits as of June 30, 2015 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of June 30, 2015 is not expected to change significantly within the next twelve months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in its consolidated statement of income. No interest is accrued on tax uncertainties as of June 30, 2015.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of June 30, 2015, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2012 for federal income taxes and for tax years prior to 2011 for Minnesota and North Dakota state income taxes. On September 13, 2013 the IRS and U.S. Treasury issued final regulations on the deductibility and capitalization of expenditures related to tangible property, generally effective for tax years beginning on or after January 1, 2014. Taxpayers were allowed to elect early adoption of the regulations for the 2012 or 2013 tax year. Deferred tax liabilities at June 30, 2015 are not materially affected by the regulations. The final regulations do not impact the effect of Revenue Procedure 2013-24 issued on April 30, 2013, which provided guidance for repairs related to generation property. Among other things, the Revenue Procedure listed units of property and material components of units of property for purposes of analyzing repair versus capitalization issues. The Company will adopt Revenue Procedure 2013-24 and the final tangible property regulations for income tax filings for tax year 2014.

16. Discontinued Operations

On April 30, 2015 the Company sold Foley Company (Foley), its former water, wastewater, power and industrial construction contractor headquartered in Kansas City, Missouri, for $12.0 million in cash plus an estimated $5.7 million adjustment for working capital and other related items, which is expected to be finalized within 120 days of the April 30, 2015 closing. Although the net carrying value of Foley had been adjusted to its indicated fair value through goodwill impairment charges recorded prior to the sale based on acceptance of the buyer's offering price, the final proceeds and loss on the sale will not be known until the adjustments for working capital and other related items have been determined. On February 28, 2015 the Company sold the assets of its former energy and electrical construction contractor headquartered in Moorhead, Minnesota (AEV, Inc.) for $22.3 million in cash plus an estimated $0.9 million in adjustments for working capital and fixed assets, which are expected to be finalized before the end of the third quarter of 2015. The Company recorded an estimated $7.2 million net-of-tax gain on the sale of AEV, Inc. The assets, liabilities, operating results and cash flows of Foley and AEV, Inc. are being reported as discontinued operations as of, and for the periods preceding, June 30, 2015. On February 8, 2013 the Company completed the sale of substantially all the assets of its former waterfront equipment manufacturing company previously included in the Company's Manufacturing segment. On November 30, 2012 the Company completed the sale of the assets of its former wind tower manufacturing company. The following summary presentations of the results of discontinued operations for the three and six month periods ended June 30, 2015 and 2014, include the operating results of Foley, AEV, Inc. and residual expenses from the Company's former wind tower and waterfront equipment manufacturers:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Operating Revenues	$5,899	$40,247	$24,623	$65,753
Operating Expenses	9,209	36,751	31,350	63,119
Goodwill Impairment Charge	--	--	1,000	--
Operating (Loss) Income	(3,310)	3,496	(7,727)	2,634
Interest Charges	--	1	--	1
Other (Deductions) Income	(11)	14	(42)	302
Income Tax (Benefit) Expense	(1,329)	1,402	(2,705)	1,177
Net (Loss) Income from Operations	(1,992)	2,107	(5,064)	1,758
(Loss) Gain on Disposition Before Taxes	(509)	--	11,533	--
Income Tax (Benefit) Expense on Disposition	(280)	--	4,536	--
Net (Loss) Gain on Disposition	(229)	--	6,997	--
Net Income (Loss)	$(2,221)	$2,107	$1,933	$1,758

The above results for the three months ended June 30, 2015 include net losses from operations of $1.5 million from Foley and $0.5 million from the Company's former waterfront equipment manufacturer related to a settlement of a warranty claim. Included in net income from operations for the three months ended June 30, 2014 are $1.1 million from Foley and $1.0 million from AEV, Inc.

The above results for the six months ended June 30, 2015 include net losses from operations of $3.9 million from Foley, $0.8 million from AEV, Inc. and $0.5 million from the Company's former waterfront equipment manufacturer related to the settlement of a warranty claim in the second quarter of 2015 and net income of $0.1 million from the Company's former wind tower manufacturer related to a reduction in warranty reserves for expired warranties. The above results for the six months ended June 30, 2014 include net income from operations of $1.2 million from Foley and 0.5 million from AEV, Inc.

Foley and AEV, Inc. entered into fixed-price construction contracts. Revenues under these contracts were recognized on a percentage-of-completion basis. The method used to determine the progress of completion was based on the ratio of costs incurred to total estimated costs on construction projects. An increase in estimated costs on one large job in progress at Foley in excess of previous period cost estimates resulted in pretax charges in the three and six months ended June 30, 2015, of $2.1 million and $4.4 million, respectively.

In the fourth quarter of 2014 the Company entered into negotiations to sell Foley and, as a result of an impairment indicator, the Company recorded a $5.6 million goodwill impairment charge. This impairment charge was based on the indicated offering price in a signed letter of intent for the purchase of Foley. In the first quarter of 2015, Foley recorded an additional $1.0 million goodwill impairment charge as a result of a revision in the estimated valuation of Foley due to first quarter financial results. The first quarter 2015 goodwill impairment loss is reflected in the results of discontinued operations.

Following are summary presentations of the major components of assets and liabilities of discontinued operations as of June 30, 2015 and December 31, 2014:

(in thousands)	June 30, 2015	December 31, 2014
Current Assets	$133	$35,174
Goodwill and Intangibles	--	2,814
Net Plant	--	10,669
Assets of Discontinued Operations	$133	$48,657
Current Liabilities	$3,260	$22,864
Deferred Income Taxes	--	4,695
Liabilities of Discontinued Operations	$3,260	$27,559

Included in current liabilities of discontinued operations are warranty reserves. Details regarding the warranty reserves follow:

(in thousands)	2015	2014
Warranty Reserve Balance, January 1	$2,527	$3,087
Additional Provision for Warranties Made During the Year	--	--
Settlements Made During the Year	(115)	(5)
Decrease in Warranty Estimates for Prior Years	--	(133)
Warranty Reserve Balance, June 30	$2,412	$2,949

The warranty reserve balances as of June 30, 2015 relate entirely to warranties scheduled to expire over the next five years on products produced by the Company's former wind tower and waterfront equipment manufacturing companies. Expenses associated with remediation activities of these companies could be substantial. Although the assets of these companies have been sold and their operating results are reported under discontinued operations in the Company's consolidated statements of income, the Company retains responsibility for warranty claims related to the products these companies produced prior to the companies being sold. For wind towers, 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. For example, 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.

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

Results of Operations

Following is an analysis of the operating results of Otter Tail Corporation (the Company, we, us and our) by business segment for the three and six month periods ended June 30, 2015 and 2014, followed by a discussion of changes in our consolidated financial position during the six months ended June 30, 2015 and our business outlook for the remainder of 2015.

Comparison of the Three Months Ended June 30, 2015 and 2014

Consolidated operating revenues were $188.2 million for the three months ended June 30, 2015 compared with $194.4 million for the three months ended June 30, 2014. Operating income was $24.8 million for the three months ended June 30, 2015 compared with $14.8 million for the three months ended June 30, 2014. The Company recorded diluted earnings per share from continuing operations of $0.36 for the three months ended June 30, 2015 compared with $0.21 for the three months ended June 30, 2014, and total diluted earnings per share of $0.30 for the three months ended June 30, 2015 compared with $0.27 for the three months ended June 30, 2014.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and other nonelectric operating expenses for the three month periods ended June 30, 2015 and 2014 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations *(in thousands)*	June 30, 2015	June 30, 2014
Operating Revenues:		
Electric	$ 37	$ 8
Nonelectric	1	(1)
Cost of Products Sold	4	5
Other Nonelectric Expenses	34	2

Electric

Three Months Ended

(in thousands)	June 30, 2015	2014	Change	% Change
Retail Sales Revenues	$79,504	$83,360	$(3,856)	(4.6)
Wholesale Revenues – Company Generation	214	1,762	(1,548)	(87.9)
Net Revenue – Energy Trading Activity	58	408	(350)	(85.8)
Other Revenues	11,188	7,381	3,807	51.6
Total Operating Revenues	$90,964	$92,911	$(1,947)	(2.1)
Production Fuel	4,183	12,603	(8,420)	(66.8)
Purchased Power – System Use	19,684	16,476	3,208	19.5
Other Operation and Maintenance Expenses	37,754	39,774	(2,020)	(5.1)
Depreciation and Amortization	11,137	10,926	211	1.9
Property Taxes	3,262	3,387	(125)	(3.7)
Operating Income	$14,944	$9,745	$5,199	53.4
Electric kilowatt-hour (kwh) Sales *(in thousands)*				
Retail kwh Sales	993,516	1,064,115	(70,599)	(6.6)
Wholesale kwh Sales – Company Generation	8,379	57,025	(48,646)	(85.3)
Wholesale kwh Sales – Purchased Power Resold	5,517	15,612	(10,095)	(64.7)
Heating Degree Days	434	673	(239)	(35.5)
Cooling Degree Days	86	113	(27)	(23.9)

The $3.9 million decrease in retail revenue includes:

- A $3.7 million decrease in revenue related to a net decrease in fuel and purchased power costs incurred to serve retail customers. This was the result of decreased kwh sales and a 4.2% decrease in the average cost per kwh for fuel and purchased power. Wholesale prices for purchased power decreased 25.5% because milder weather in the second quarter of 2015 reduced market demand compared with the second quarter of 2014.

- A $2.0 million decrease in revenues related to the 6.6% decrease in retail kwh sales, mainly reflecting a decrease in sales to residential and commercial customers due, in part, to milder weather in the second quarter of 2015, evidenced by heating-degree days that were 35.5% lower than in the second quarter of 2014 and 82.7% of normal.

- A $0.9 million decrease in Transmission Costs Recovery (TCR) rider revenues mainly due to increased recovery of transmission costs from other users of OTP's transmission system.

offset by:

- A $2.7 million increase in Environmental Cost Recovery (ECR) rider revenue related to earning a return in North Dakota and Minnesota on increasing amounts invested in the air quality control system (AQCS) nearing completion at Big Stone Plant and the initiation of an ECR rider in South Dakota in December 2014 to recover costs and earn a return on amounts invested in the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) projects. Effective in the second quarter of 2015, North Dakota ECR revenues also include a return on and recovery of MATS costs.

Wholesale electric revenues from company-owned generation decreased $1.5 million as a result of an 85.3% reduction in wholesale kwh sales combined with a 17.3% decrease in revenue per wholesale kwh sold. The decreases in wholesale kwh sales and prices were driven by decreased wholesale market demand resulting from milder weather in the second quarter of 2015. Also, Otter Tail Power Company (OTP) had fewer resources available for selling into the wholesale market as Big Stone Plant was off line for the entire second quarter of 2015 for an extended maintenance outage that required off-site turbine blade replacements and repairs. Coyote Station was operating at reduced load due to ongoing repairs related to a December 2014 boiler feed pump failure and ensuing fire.

Net revenues from energy trading activities decreased $0.4 million as a result of OTP ending its trading activities not directly associated with serving its retail customers in December 2014.

Other electric revenues increased $3.8 million due to a $4.2 million increase in Midcontinent Independent System Operator, Inc. (MISO) transmission tariff revenues related to increased investment in regional transmission lines, offset by a $0.4 million decrease in steam sales to an ethanol plant next to Big Stone Plant as a result of Big Stone Plant being down for maintenance and turbine repairs in the second quarter of 2015.

Production fuel costs decreased $7.5 million to serve retail customers and $0.9 million for wholesale sales as a result of a 68.4% decrease in kwhs generated from OTP's steam-powered and combustion turbine generators primarily due to the factors discussed above.

The cost of purchased power to serve retail customers increased $3.2 million, reflecting a $7.4 million volume variance due to a 60.4% increase in kwhs purchased, partially offset by a $4.2 million price variance due to a 25.5% decrease in the cost per kwh purchased. The increase in power purchases for retail sales was necessitated by the reduced availability of company-owned generating capacity discussed above. The decreased cost per kwh purchased was driven by lower market demand mainly resulting from milder weather in the second quarter of 2015.

Electric operating and maintenance expenses decreased $2.0 million mainly as a result of:

- A $3.4 million reduction in Hoot Lake Plant maintenance costs related to costs incurred during its extended spring outage in the second quarter of 2014.
- Reductions of $0.6 million in vegetation and substation maintenance expense.
- A $0.6 million reduction in vehicle and administrative and general expense related to an increase in vehicle usage and administrative and general costs charged to capital projects.
- A $0.5 million reduction in generation plant maintenance at Coyote Station and the Luverne and Ashtabula wind farms.
- A discount of $0.3 million recorded in June 2014 related to OTP not earning a return on the deferred recovery of the Minnesota share of Big Stone II abandoned transmission costs. No comparable discount expense was recorded in the second quarter of 2015.

offset by:

- A $1.7 million increase in MISO transmission service charges related to increasing investments in regional transmission projects.
- A $1.6 million increase in operating and maintenance expenses related to Big Stone Plant's spring 2015 extended maintenance outage.

Manufacturing

(in thousands)	Three Months Ended June 30, 2015	2014	Change	% Change
Operating Revenues	$51,273	$53,370	$(2,097)	(3.9)
Cost of Products Sold	39,525	41,185	(1,660)	(4.0)
Operating Expenses	5,224	5,100	124	2.4
Depreciation and Amortization	2,633	2,650	(17)	(0.6)
Operating Income	$3,891	$4,435	$(544)	(12.3)

The decrease in revenues in our Manufacturing segment reflects the following:

- Revenues at BTD Manufacturing, Inc. (BTD), our metal parts stamping and fabrication company, decreased $2.9 million reflecting a $4.9 million decrease in sales to manufacturers of oil and gas exploration and extraction equipment as a result of a reduction in drilling activity related to current low oil prices. Revenue from the sale of scrap metal decreased of $0.7 million due to a 40% reduction in prices compared with the second quarter of 2014. These decreases were partially offset by a $2.7 million net increase in sales to other customers, mainly manufacturers of lawn and garden and recreational equipment.

- Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, increased $0.8 million, mainly due to a $0.6 million increase in sales of horticultural products. An increase in sales of various other products to industrial customers also contributed $0.2 million to the increase in revenue.

The decrease in cost of products sold in our Manufacturing segment relates to the following:

- Cost of products sold at BTD decreased $2.2 million, mainly as a result of a $1.6 million decrease in labor and material costs, primarily related to the reduction in sales to manufacturers of oil and gas exploration and agricultural equipment and a reduction in the labor force producing those products.

- Cost of products sold at T.O. Plastics increased $0.6 million due to increases in material and labor costs related to the increase in sales at T.O. Plastics.

Plastics

(in thousands)	Three Months Ended June 30, 2015	2014	Change	% Change
Operating Revenues	$45,954	$48,090	$(2,136)	(4.4)
Cost of Products Sold	35,465	38,998	(3,533)	(9.1)
Operating Expenses	2,405	2,425	(20)	(0.8)
Depreciation and Amortization	863	866	(3)	(0.3)
Operating Income	$7,221	$5,801	$1,420	24.5

The $2.1 million decrease in Plastics segment revenues is the result of a 5% decrease in the price per pound of polyvinyl chloride (PVC) pipe sold related to falling resin prices, partially offset by a 0.4% increase in pounds of pipe sold. The $3.5 million decrease in costs of products sold is due to a 9.4% decrease in the cost per pound of pipe sold, mainly related to a decrease in material costs due to lower resin prices, which were partially offset by an increase in allocated overhead costs and the 0.4% increase in sales volume.

Corporate

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

(in thousands)	Three Months Ended June 30, 2015	2014	Change	% Change
Operating Expenses	$1,228	$5,199	$(3,971)	(76.4)
Depreciation and Amortization	28	30	(2)	(6.7)

Corporate operating expenses decreased $4.0 million due to:

- A $2.7 million reduction in airplane operating lease expense related to the early termination of an airplane lease in the second quarter of 2014, as divestitures had reduced the need for the airplane. The cost to terminate the lease early was approximately $2.5 million.

- A $0.8 million decrease in stock-based performance incentive costs related to a decrease in the market value of the Company's common stock in the second quarter 2015.

- A $0.5 million reduction in other labor and benefit costs.

Other Income

The $0.3 million decrease in other income in the three months ended June 30, 2015 compared with the three months ended June 30, 2014, reflects (1) a $0.2 million reduction in other income at OTP related to reductions in allowances for funds used during construction (AFUDC) and carrying charges earned on funds invested in Minnesota conservation improvement programs, in alignment with the decrease in short-term borrowing rates, and (2) a $0.1 million reduction in increases in cash surrender values of corporate-owned life insurance between the quarters.

Income Taxes – Continuing Operations

Income tax expense - continuing operations increased $3.9 million mainly as a result of a $9.7 million increase in income from continuing operations before income taxes between the second quarter of 2015 and the second quarter of 2014. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on our consolidated statements of income for the three month periods ended June 30, 2015 and 2014:

	Three Months Ended June 30,	
(in thousands)	2015	2014
Income Before Income Taxes – Continuing Operations	$17,665	$7,970
Tax Computed at Company’s Net Composite Federal and State Statutory Rate (39%)	6,889	3,108
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(1,656)	(1,864)
Section 199 Domestic Production Activities Deduction	(363)	(349)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(213)	(212)
Corporate Owned Life Insurance	(185)	(199)
Employee Stock Ownership Plan Dividend Deduction	(171)	(189)
Investment Tax Credits	(143)	(127)
AFUDC Equity	(125)	(164)
Other Items – Net	(25)	80
Income Tax Expense – Continuing Operations	$4,008	$84
Effective Income Tax Rate – Continuing Operations	22.7 %	1.1 %

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP’s kwh generation from its wind turbines eligible for PTCs decreased 10.8% due to lower average wind speed in the three months ended June 30, 2015 compared with the three months ended June 30, 2014. 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.

Discontinued Operations

On April 30, 2015 we sold Foley Company (Foley), our former water, wastewater, power and industrial construction contractor for $12.0 million in cash plus an estimated $5.7 million adjustment for working capital and other related items, which is expected to be finalized within 120 days of the April 30, 2015 closing. Although the net carrying value of Foley had been adjusted to its indicated fair value through goodwill impairment charges recorded prior to the sale based on acceptance of the buyer's offering price, the final proceeds and loss on sale will not be known until the adjustments for working capital and other related items have been determined. On February 28, 2015 we sold the assets of our former energy and electrical construction contractor (AEV, Inc.) for $22.3 million in cash plus an estimated $0.9 million in adjustments for working capital and fixed assets, which are expected to be finalized before the end of the third quarter of 2015. We recorded an estimated $7.2 million net-of-tax gain on the sale of AEV, Inc. On February 8, 2013 we completed the sale of substantially all the assets of our former waterfront equipment manufacturing company previously included in our Manufacturing segment. On November 30, 2012 we completed the sale of the assets of our former wind tower manufacturing company. The following summary presentations of the results of discontinued operations for the three-month periods ended June 30, 2015 and 2014, include the operating results of Foley and AEV, Inc. and residual expenses from our former wind tower and waterfront equipment manufacturers:

	For the Three Months Ended June 30,				
(in thousands)	2015			2014	
Operating Revenues	$	5,899		$	40,247
Operating Expenses		9,209			36,751
Operating (Loss) Income		(3,310	)		3,496
Interest Charges		--			1
Other (Deductions) Income		(11	)		14
Income Tax (Benefit) Expense		(1,329	)		1,402
Net (Loss) Income from Operations		(1,992	)		2,107
Loss on Disposition Before Taxes		(509	)		--
Income Tax Benefit on Disposition		(280	)		--
Net Loss on Disposition		(229	)		--
Net Income (Loss)	$	(2,221	)	$	2,107

The above results for the three months ended June 30, 2015 include net losses from operations of $1.5 million from Foley and $0.5 million from our former waterfront equipment manufacturer related to a settlement of a warranty claim. Included in net income from operations for the three months ended June 30, 2014 are $1.1 million from Foley and $1.0 million from AEV, Inc.

Comparison of the Six Months Ended June 30, 2015 and 2014

Consolidated operating revenues were $391.0 million for the six months ended June 30, 2015 compared with $409.3 million for the six months ended June 30, 2014. Operating income was $49.8 million for the six months ended June 30, 2015 compared with $50.2 million for the six months ended June 30, 2014. The Company recorded diluted earnings per share from continuing operations of $0.73 for the six months ended June 30, 2015 compared to $0.81 for the six months ended June 30, 2014 and total diluted earnings per share of $0.78 for the six months ended June 30, 2015 compared to $0.86 for the six months ended June 30, 2014.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the six month periods ended June 30, 2015 and 2014 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations *(in thousands)*	June 30, 2015	June 30, 2014
Operating Revenues:		
Electric	$ 51	$ 48
Nonelectric	4	(1)
Cost of Products Sold	4	7
Other Nonelectric Expenses	51	40

38

Electric

(in thousands)	Six Months Ended June 30, 2015	2014	Change	% Change
Retail Sales Revenues	$183,118	$188,864	$(5,746)	(3.0)
Wholesale Revenues – Company Generation	1,274	6,662	(5,388)	(80.9)
Net Revenue – Energy Trading Activity	185	139	46	33.1
Other Revenues	19,934	16,334	3,600	22.0
Total Operating Revenues	$204,511	$211,999	$(7,488)	(3.5)
Production Fuel	18,782	34,633	(15,851)	(45.8)
Purchased Power – System Use	43,376	38,261	5,115	13.4
Other Operation and Maintenance Expenses	75,281	74,396	885	1.2
Depreciation and Amortization	22,201	21,689	512	2.4
Property Taxes	6,764	6,358	406	6.4
Operating Income	$38,107	$36,662	$1,445	3.9
Electric kwh Sales *(in thousands)*				
Retail kwh Sales	2,355,199	2,462,006	(106,807)	(4.3)
Wholesale kwh Sales – Company Generation	44,476	130,330	(85,854)	(65.9)
Wholesale kwh Sales – Purchased Power Resold	5,537	17,223	(11,686)	(67.9)
Heating Degree Days	3,771	4,762	(991)	(20.8)
Cooling Degree Days	86	113	(27)	(23.9)

The $5.7 million decrease in retail revenue includes:

- A $5.3 million decrease in revenue due to a net decrease in fuel and purchased power cost incurred to serve retail customers related to the decrease in kwh sales.

- A $4.5 million decrease in revenues related to the 4.3% decrease in retail kwh sales mainly resulting from milder weather in the first half of 2015, evidenced by heating-degree days that were 20.8% lower than the first half of 2014 and 94.7% of normal.

- A $1.2 million decrease in TCR rider revenues, mainly in Minnesota, due in part to increased recovery of transmission costs from other users of OTP's transmission system.

- A $0.4 million reduction in Big Stone II Cost Recovery rider revenues as the North Dakota share of abandoned plant costs were fully recovered as of March 31, 2014.

offset by:

- A $4.7 million increase in ECR rider revenues related to earning a return in North Dakota and Minnesota on increasing amounts invested in the AQCS nearing completion at Big Stone Plant, and the initiation of an ECR rider in South Dakota in December 2014 to recover costs and earn a return on amounts invested in the Big Stone Plant AQCS and the Hoot Lake Plant MATS project. Effective in the second quarter of 2015, North Dakota ECR revenues also include a return on and recovery of MATS costs.

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- A $0.6 million increase in revenues recoverable under CIP riders related to an increase in conservation program incentives awarded for 2014 program results and an increase in CIP recoverable expenditures, both in 2015.

- A $0.4 million increase in North Dakota Renewable Resource Adjustment (NDRRA) rider revenues related to a 9.8% reduction in kwh generation from company-owned wind turbines eligible for federal PTCs, which resulted in fewer PTCs being passed back to customers through the NDRRA between the periods.

Wholesale electric revenues from company-owned generation decreased $5.4 million as a result of a 65.9% reduction in wholesale kwh sales combined with a 44.0% decrease in revenue per wholesale kwh sold. The decreases in wholesale kwh sales and prices were driven by decreased wholesale market demand resulting from milder weather in the first half of 2015. Also, OTP had fewer resources available for selling into the wholesale market as Big Stone Plant has been off line since February 27, 2015 for an extended maintenance outage that required off-site turbine blade replacements and repairs and Coyote Station has been operating at reduced load since December 2014 due to ongoing repairs related to a boiler feed pump failure and ensuing fire. Additionally, Hoot Lake Plant was curtailed due to low market prices for electricity and generation from company-owned wind turbines was down 7.3% from the first six months of 2014 due to icing, scheduled repairs and lower average wind speed.

Other electric revenues increased $3.6 million due to:

- A $4.9 million increase in MISO transmission tariff revenues related to increased investment in regional transmission projects.

offset by:

- A $0.9 million decrease in steam sales to an ethanol plant next to Big Stone Plant as a result of Big Stone Plant being down for extended maintenance and turbine repairs.

- A $0.3 million decrease in revenue related to a reduction in work done on lines owned by another regional transmission provider.

- A $0.1 million reduction in estimated reimbursements related to shared use of regional transmission facilities.

Production fuel costs decreased $15.9 million as a result of a 45.5% decrease in kwhs generated from OTP's steam-powered and combustion turbine generators primarily due to the factors discussed above. The cost of purchased power to serve retail customers increased $5.1 million due to a 51.5% increase in kwhs purchased, partially offset by a 25.2% decrease in the cost per kwh purchased. The increase in power purchases for retail sales was necessitated by the reduced availability of company-owned generating capacity discussed above. The decreased cost per kwh purchased was driven by lower market demand mainly resulting from milder weather in the first half of 2015.

Electric operating and maintenance expenses increased $0.9 million reflecting:

- A $2.5 million increase in MISO transmission service charges related to increasing investments in regional transmission projects.

- A $0.6 million increase in labor benefit costs, mainly related to an increase in corporate costs allocated to utility operations and increased leadership training costs.

offset by:

- A $0.9 million reduction in vehicle and administrative and general expense related to an increase in vehicle usage and administrative and general costs charged to capital projects.

- A $0.6 million net reduction in steam generation plant maintenance costs.

- A $0.4 million reduction in the amortization of the North Dakota share of Big Stone II abandoned plant costs, which were fully recovered by the end of March 2014

- A discount of $0.3 million recorded in June 2014 related to OTP not earning a return on the deferred recovery of the Minnesota share of Big Stone II abandoned transmission costs. No comparable discount expense was recorded in 2015.

Depreciation expense increased $0.5 million as a result of increased investment in transmission, distribution and general plant placed in service in 2014 and 2015.

The $0.4 million increase in property tax expense was due to higher assessed values of property in Minnesota and South Dakota in combination with increasing investments in transmission and distribution property, mainly in Minnesota.

Manufacturing

(in thousands)	Six Months Ended June 30, 2015	2014	Change	% Change
Operating Revenues	$108,032	$108,805	$(773)	(0.7)
Cost of Products Sold	85,224	83,384	1,840	2.2
Operating Expenses	11,162	10,325	837	8.1
Depreciation and Amortization	5,225	5,270	(45)	(0.9)
Operating Income	$6,421	$9,826	$(3,405)	(34.7)

The decrease in revenues in our Manufacturing segment reflects the following:

- Revenues at BTD decreased $2.4 million reflecting a $6.8 million decrease in sales to manufacturers of oil and gas exploration and extraction equipment as a result of a reduction in drilling activity related to current low oil prices. The decrease also reflects a decrease of $1.3 million in revenue from sales of scrap metal due to a 40% reduction in prices compared with 2014. These decreases were partially offset by a $5.6 million net increase in sales mainly to manufacturers of lawn and garden equipment.

- Revenues at T.O. Plastics increased $1.6 million, mainly due to a $1.0 million increase in sales of horticultural products. Increases in sales of extruded products and sales to industrial customers contributed $0.6 million to the increase in revenue.

The increase in cost of products sold in our Manufacturing segment relates to the following:

- Cost of products sold at BTD increased $0.1 million, as increases in material and freight costs related to the increase in sales to manufacturers of lawn and garden equipment and payments of workforce reduction benefits offset reductions in labor, material and direct production costs related to the reduction in sales to manufacturers of oil and gas exploration and extraction equipment.

- Cost of products sold at T.O. Plastics increased $1.7 million, mainly due to a $1.2 million increase in material and direct labor costs related to increased sales and a $0.3 million increase in shipping costs related to less than full load shipments of horticultural products to meet customer demand and delivery dates in the first quarter of 2015.

The increase in operating expenses in our Manufacturing segment is mostly due to a $0.6 million increase in employee benefit expenses at BTD and a $0.2 million increase in sales related expense at T.O. Plastics.

Plastics

	Six Months Ended June 30,			%
(in thousands)	2015	2014	Change	Change
Operating Revenues	$78,506	$88,573	$(10,067)	(11.4)
Cost of Products Sold	61,264	70,740	(9,476)	(13.4)
Operating Expenses	4,695	4,542	153	3.4
Depreciation and Amortization	1,711	1,719	(8)	(0.5)
Operating Income	$10,836	$11,572	$(736)	(6.4)

The $10.1 million decrease in Plastic segment revenues is the result of a 9.1% decrease in pounds of PVC pipe sold in combination with a 2.5% decrease in the price per pound of pipe sold. The decrease in sales are due in part to delayed purchases related to falling resin prices and in part to reduced demand in the region of the United States between the Mississippi River and the Rocky Mountain states, especially in Texas where soft markets were exacerbated by severe spring flooding. The $9.5 million decrease in costs of products sold is due to the decrease in sales volume in combination with a 4.7% decrease in the cost per pound of pipe sold mainly related to a decrease in material costs due to lower resin prices. The $0.2 million increase in operating expenses was mainly related to an increase in wage and benefit costs.

Corporate

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

	Six Months Ended June 30,			%
(in thousands)	2015	2014	Change	Change
Operating Expenses	$ 5,480	$ 7,846	$ (2,366)	(30.2)
Depreciation and Amortization	59	61	(2)	(3.3)

41

The $2.4 million decrease in corporate operating expenses includes:

- A $2.8 million reduction in airplane operating lease expense related to the early termination of an airplane lease in the second quarter of 2014, as divestitures had reduced the need for the airplane. The cost to terminate the lease early was approximately $2.5 million.

- A net increase in corporate costs allocated to utility operations of approximately $0.8 million related to an increase in corporate benefit and stock incentive costs and higher allocation rates resulting from recent divestitures of nonutility operations.

offset by:

- A $0.9 million increase in labor and benefit costs mainly due to increased health insurance costs.

- A $0.2 million increase in costs related to leadership development and leadership succession.

Interest Charges

The $1.2 million increase in interest charges in the six months ended June 30, 2015 compared with the six months ended June 30, 2014 is mainly due to a $1.3 million increase in interest expense incurred in January and February of 2015 at OTP related to the February 27, 2014 issuance of $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044. OTP used a portion of the proceeds from the issuance of the Series A and B Senior Unsecured Notes referenced above to retire OTP's $40.9 million unsecured term loan and repay $82.5 million of short-term debt then outstanding under the OTP Credit Agreement.

Other Income

The $1.2 million decrease in other income in the six months ended June 30, 2015 compared with the six months ended June 30, 2014, reflects a $0.8 million gain on the sale of an investment in tax-credit-qualified low income housing rental property in the first quarter of 2014 that was not duplicated in the first half of 2015 along with a $0.4 million reduction in other income at OTP related to reductions in AFUDC and carrying charges earned on funds invested in Minnesota conservation improvement programs prior to recovery, in alignment with the decrease in short-term borrowing rates.

Income Taxes – Continuing Operations

Income tax expense – continuing operations decreased $0.6 million mainly as a result of a $1.1 million reduction in income taxes related to a $2.8 million decrease in income before income taxes – continuing operations for the six months ended June 30, 2015 compared with the six months ended June 30, 2014, offset by a $0.4 million reduction in federal PTCs earned between the periods. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on our consolidated statements of income for the six month periods ended June 30, 2015 and 2014:

	Six Months Ended June 30,

(in thousands)	2015	2014
Income Before Income Taxes – Continuing Operations	$35,519	$38,311
Tax Computed at Company’s Net Composite Federal and State Statutory Rate (39%)	13,852	14,941
Increases (Decreases) in Tax from:		
Federal PTCs	(3,710)	(4,116)
Section 199 Domestic Production Activities Deduction	(725)	(707)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(425)	(425)
Employee Stock Ownership Plan Dividend Deduction	(343)	(379)
Investment Tax Credits	(286)	(254)
AFUDC Equity	(225)	(297)
Other Items - Net	(57)	(117)
Income Tax Expense – Continuing Operations	$8,081	$8,646
Effective Income Tax Rate – Continuing Operations	22.8 %	22.6 %

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs decreased 9.8% due to icing, scheduled repairs and lower average wind speed in the six months ended June 30, 2015 compared with the six months ended June 30, 2014. 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.

Discontinued Operations

On April 30, 2015 we sold Foley for $12.0 million in cash plus an estimated $5.7 million adjustment for working capital and other related items, which is expected to be finalized within 120 days of the April 30, 2015 closing. Although the net carrying value of Foley had been adjusted to its indicated fair value through goodwill impairment charges recorded prior to the sale based on acceptance of the buyer's offering price, the final proceeds and loss on sale will not be known until the adjustments for working capital and other related items have been determined. On February 28, 2015 we sold the assets of AEV, Inc. for $22.3 million in cash plus an estimated $0.9 million in adjustments for working capital and fixed assets, which are expected to be finalized before the end of the third quarter of 2015. We recorded an estimated $7.2 million net-of-tax gain on the sale of AEV, Inc. On February 8, 2013 we completed the sale of substantially all the assets of our former waterfront equipment manufacturing company previously included in the our Manufacturing segment. On November 30, 2012 we completed the sale of the assets of our former wind tower manufacturing company. The following summary presentations of the results of discontinued operations for the six-month periods ended June 30, 2015 and 2014, include the operating results of Foley and AEV, Inc. and residual expenses from our former wind tower and waterfront equipment manufacturers:

	For the Six Months Ended June 30,	
(in thousands)	2015	2014
Operating Revenues	$24,623	$65,753
Operating Expenses	31,350	63,119
Goodwill Impairment Charge	1,000	--
Operating (Loss) Income	(7,727)	2,634
Interest Charges	--	1
Other (Deductions) Income	(42)	302
Income Tax (Benefit) Expense	(2,705)	1,177
Net (Loss) Income from Operations	(5,064)	1,758
Gain on Disposition Before Taxes	11,533	--
Income Tax Expense on Disposition	4,536	--
Net Gain on Disposition	6,997	--
Net Income	$1,933	$1,758

The above results for the six months ended June 30, 2015 include net losses from operations of $3.9 million from Foley, $0.8 million from AEV, Inc. and $0.5 million from our former waterfront equipment manufacturer related to the settlement of a warranty claim in the second quarter of 2015 and net income of $0.1 million from our former wind tower manufacturer related to a reduction in warranty reserves for expired warranties. The above results for the six months ended June 30, 2014 include net income from operations of $1.2 million from Foley and 0.5 million from AEV, Inc.

FINANCIAL POSITION

The following table presents the status of our lines of credit as of June 30, 2015 and December 31, 2014:

(in thousands)	Line Limit	In Use on June 30, 2015	Restricted due to Outstanding Letters of Credit	Available on June 30, 2015	Available on December 31, 2014
Otter Tail Corporation Credit Agreement	$150,000	$38,494	$ 150	$111,356	$138,872
OTP Credit Agreement	170,000	4,546	310	165,144	169,440
Total	$320,000	$43,040	$ 460	$276,500	$308,312

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if needed. Our balance sheet is strong and we are in compliance with our debt covenants. Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings and alternative financing arrangements such as leasing.

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects.

Equity or debt financing will be required in the period 2015 through 2019 given the expansion plans related to our Electric segment to fund construction of new rate base investments. Also, such financing will be required should we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. 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.

The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by our subsidiaries. See note 8 to consolidated financial statements for more information. The decision to declare a dividend is reviewed quarterly by the board of directors. On February 3, 2015 our board of directors increased the quarterly dividend from $0.3025 to $0.3075 per common share.

Cash provided by operating activities from continuing operations was $52.7 million for the six months ended June 30, 2015 compared with $20.5 million for the six months ended June 30, 2014. The main contributing factors to the $32.2 million increase in cash provided by operating activities were changes in deferred debits and credits and other long-term assets and liabilities totaling $16.3 million mainly related to a reduction in net regulatory assets at OTP, a $10.0 million decrease in discretionary contributions to the corporation's pension plan and an $8.0 million decrease in cash used for working capital items, offset by a $2.2 million decrease in net income from continuing operations between the periods. The decrease in cash used for working capital items mainly reflects a $3.2 million reduction in inventories at the PVC pipe companies in the first six months of 2015 compared with a $6.8 million increase in PVC pipe company inventories in the first six months of 2014.

In continuing operations, net cash used in investing activities was $86.6 million for the six months ended June 30, 2015 compared with $79.8 million for the six months ended June 30, 2014. A $4.1 million increase in cash used for investments between periods, including $2.5 million in funds from the sales of AEV, Inc, and Foley that have been deposited in escrow accounts, was partially offset by a $1.2 million decrease in proceeds from the disposal of noncurrent assets. A $3.8 million increase in cash used for capital expenditures reflects a $9.4 million increase in cash used for capital expenditures in our Manufacturing segment, mainly at BTD as it moves forward with its project to expand and realign its Minnesota production and warehouse facilities, offset by a $6.0 million reduction in capital expenditures at OTP as several major projects begin to wind down, including two CapX2020 transmission line projects and the new AQCS at Big Stone Plant.

First half 2015 investing activities of discontinued operations includes $21.3 million in cash proceeds from the sale of the assets of AEV, Inc., and $11.4 million from the sale of Foley stock, partially offset by $1.8 million in cash used in investing activities of discontinued operations, mainly related to the purchase by AEV, Inc. of assets being leased under operating leases prior to the assets being sold.

Net cash provided by financing activities of continuing operations was $13.5 million in the six months ended June 30, 2015 compared with $73.1 million for the six months ended June 30, 2014. Net cash provided by financing activities in the first six months of 2015 includes $32.2 million in short-term borrowings used, in part, to fund capital expenditures, and $7.1 million in proceeds from the issuance of common stock under our various stock purchase and dividend reinvestment plans, offset by $23.0 million in common stock dividend payments. See note 6 to the Company's consolidated financial statements for further information on stock issuances and retirements in the first half of 2015.

Net cash provided by financing activities of continuing operations in the first six months of 2014 mainly reflects the issuance by OTP of $150 million in privately placed unsecured notes in two series on February 27, 2014, and the use of a portion of the proceeds of the notes to retire OTP's $40.9 million unsecured term loan and to repay short-term debt outstanding under the OTP Credit Agreement which was being used to finance OTP's construction activities. Financing activities in the first six months of 2014 also reflect: (1) the payment of $22.0 million in common stock dividends, (2) OTP's repayment of $51.2 million in short-term debt that was outstanding under the OTP Credit Agreement on December 31, 2013, (3) the borrowing of $25.3 million under the Otter Tail Corporation Credit Agreement to fund the working capital needs of our manufacturing and infrastructure companies and (4) the borrowing of $2.9 million under the OTP Credit Agreement to fund a portion of OTP's 2014 capital expenditures. Financing cash flows for the first six months of 2014 also included $8.5 million in cash proceeds from the issuance of common stock. In 2014, we began issuing common shares to meet the requirements of our dividend reinvestment and share purchase plan, employee stock ownership plan and employee stock purchase plan, rather than purchasing shares in the open market. In the second quarter of 2014 we began issuing common shares using our At-the-Market offering program under our Distribution Agreement with J.P. Morgan Securities (JPMS).

CAPITAL REQUIREMENTS

Contractual Obligations

Our contractual obligations reported in the table on page 51 of our Annual Report on Form 10-K for the year ended December 31, 2014 increased $29.4 million in the first six months of 2015. Our purchase obligations under coal contract commitments increased $1.3 million for 2015 and $8.7 million for 2016 and 2017 as a result of OTP entering into a contract in the first quarter of 2015 for the purchase of coal to meet a portion of Big Stone Plant's future coal requirements. Our obligations related to capacity and energy requirements increased $6.9 million for 2015 as a result of OTP entering into energy purchase agreements in the first half of 2015 for the purchase of electricity in April, May, June and July of 2015 to make up for reduced generation at Coyote Station and Big Stone Plant. Our operating lease obligations increased $0.7 million in 2015, $1.9 million in 2016 and 2017 and $0.2 million in 2018 as a result of OTP entering into an agreement in April 2015 to extend the term of its lease of rail cars used for the transport of coal to Hoot Lake Plant by 36 months, beginning April 1, 2015. Our commitments under construction contracts increased $9.7 million in 2015 in connection with contracts for the construction of the Big Stone South to Ellendale transmission line project.

CAPITAL RESOURCES

On May 11, 2015 we filed a shelf registration statement with the Securities and Exchange Commission (SEC) under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 10, 2018. On May 11, 2015, we entered into a Distribution Agreement with JPMS under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million. In the second quarter of 2015 we sold no common shares under this program.

Short-Term Debt

The following table presents the status of our lines of credit as of June 30, 2015 and December 31, 2014:

(in thousands)	Line Limit	In Use on June 30, 2015	Restricted due to Outstanding Letters of Credit	Available on June 30, 2015	Available on December 31, 2014
Otter Tail Corporation Credit Agreement	$150,000	$ 38,494	$ 150	$ 111,356	$ 138,872
OTP Credit Agreement	170,000	4,546	310	165,144	169,440
Total	$320,000	$ 43,040	$ 460	$ 276,500	$ 308,312

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured $150 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement. On November 3, 2014 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2018 to October 29, 2019. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations of our subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.75%, subject to adjustment based on our senior unsecured credit ratings. We are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Otter Tail Corporation Credit Agreement contains a number of restrictions on us and the businesses of the Company's wholly owned subsidiary, Varistar Corporation, and its subsidiaries, including restrictions on our and their ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of our subsidiaries. Outstanding letters of credit issued by us under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $40 million.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured $170 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On November 3, 2014 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2018 to October 29, 2019. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP

Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading “Financial Covenants.” The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP’s credit ratings. OTP’s obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the Purchasers named therein, pursuant to which OTP agreed to issue to the Purchasers, in a private placement transaction, $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). On February 27, 2014 OTP issued all $150 million aggregate principal amount of the Notes. OTP used a portion of the proceeds of the Notes to retire its $40.9 million term loan under a Credit Agreement with JPMorgan Chase Bank, N.A. and to repay $82.5 million of short-term debt then outstanding under the OTP Credit Agreement. Remaining proceeds of the Notes were used to fund OTP construction program expenditures.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (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, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP.

The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2013 Note Purchase 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 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event OTP's existing credit agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an "Additional Covenant"), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued $140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (2011 Note Purchase Agreement). OTP also has outstanding its $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 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement).

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP 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. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP 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 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP 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 OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

Financial Covenants

We were in compliance with the financial covenants in our debt agreements as of June 30, 2015.

No Credit or Note Purchase Agreement contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

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

Under the Otter Tail Corporation Credit Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Otter Tail Corporation Credit Agreement. As of June 30, 2015 our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement was 3.48 to 1.00.

Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.

Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, 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 to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of June 30, 2015 OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 3.24 to 1.00.

Under the 2013 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, each as provided in the 2013 Note Purchase Agreement.

As of June 30, 2015 our ratio of interest-bearing debt to total capitalization was 0.48 to 1.00 on a consolidated basis and 0.48 to 1.00 for OTP.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $5.7 million, but our line of credit borrowing limits are only restricted by $0.5 million of the outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2015 BUSINESS OUTLOOK

We are maintaining our consolidated diluted earnings per share guidance for 2015 to be in the range of $1.50 to $1.65 but now expect to be in the middle to upper end of the range. This guidance reflects the current mix of businesses owned by us. It considers the cyclical nature of some of our businesses and reflects challenges, as well as our plans and strategies for improving future operating results.

Segment components of our 2014 diluted earnings per share and 2015 diluted earnings per share guidance range for continuing operations are as follows:

	2014	Initial 2015 Guidance February 9, 2015		2015 Guidance Revised May 4, 2015		2015 Guidance August 3, 2015	
Diluted Earnings Per Share		Low	High	Low	High	Low	High
Electric	$1.19	$1.26	$1.29	$1.23	$1.26	$1.23	$1.26
Manufacturing	$0.25	$0.37	$0.41	$0.21	$0.25	$0.21	$0.25
Plastics	$0.33	$0.25	$0.29	$0.29	$0.33	$0.29	$0.33
Corporate	$(0.22)	$(0.23)	$(0.19)	$(0.23)	$(0.19)	$(0.23)	$(0.19)
Total – Continuing Operations	$1.55	$1.65	$1.80	$1.50	$1.65	$1.50	$1.65
Expected Return on Equity				9.5 %	10.4 %	9.5 %	10.4 %

Contributing to our earnings guidance for 2015 are the following items:

We expect 2015 net income to be better than 2014 net income for our Electric segment. Items affecting this increase include:

- Rider recovery increases, including environmental riders in Minnesota, North Dakota and South Dakota related to the Big Stone AQCS environmental upgrades while under construction.
- Expected increases in sales to pipeline customers.
- A decrease in plant maintenance costs, as unanticipated maintenance issues encountered during the 2014 Hoot Lake Plant shutdown are not expected to occur in 2015.

offset by:

- Lower retail sales due to milder than normal weather.
- Higher than expected claim costs and more participants associated with the long-term disability plans.
- An increase in coal plant reagent costs that were determined unrecoverable under rider by the Minnesota Public Utilities Commission in March 2015.
- A decrease in transmission revenues for a potential reduction in the rate of return on equity granted by the Federal Energy Regulatory Commission under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.
- An increase in pension costs as a result of an increase in projected benefit obligations based on a decrease in the discount rate from 5.30% to 4.35% and adoption of new mortality tables which have longer life expectancy assumptions.
- Higher depreciation and property tax expense due to increased investment in transmission, generation, distribution and general plant placed in service in 2014 and 2015.
- Higher short-term interest costs as major projects continue to be funded under OTP's credit agreement.

We expect 2015 net income guidance from our Manufacturing segment to be near or slightly below 2014 net income due to:

- Continued softness in the agriculture, energy, mining and oil and gas equipment end markets served by BTD's customers, declining commodity prices for scrap and increased costs of manufacturing due to lower productivity.
- Backlog for the manufacturing companies of approximately $85 million for 2015 compared with $86 million one year ago.

We expect 2015 net income from our Plastics segment to be the same or slightly below 2014 net income as a result of an anticipated decrease in PVC pipe sales, partially offset by better margins as a result of material cost decreases that have exceeded decreases in PVC pipe prices.

We expect corporate costs in 2015 to be in line with, or slightly lower than, 2014 costs.

Critical Accounting Policies Involving Significant Estimates

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

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, accrued renewable resource, transmission, and environmental cost recovery rider revenues, valuations of forward energy contracts, warranty 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 56 through 60 of our Annual Report on Form 10-K for the year ended December 31, 2014. With the sale of Foley in April 2015 we no longer own any construction businesses applying percentage-of-completion accounting and, subsequent to the sale of Foley, our results of operations are no longer subject to adjustments related to changes in estimates of projected costs used to determine expected profits and progress toward completion on construction jobs in progress. However, costs in excess of billings and billings in excess of costs are components of working capital that were transferred in the sales of the construction companies and are subject to adjustment until agreement is reached on final working capital settlements expected in the third quarter of 2015. There were no other material changes in critical accounting policies or estimates during the quarter ended June 30, 2015.

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

In connection with the “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995 (the Act), we have filed cautionary statements identifying important factors that could cause our actual results to differ materially from those discussed in forward-looking statements made by or on behalf of the Company. When used in this Form 10-Q and in future filings by the Company with the Securities and Exchange Commission, in our press releases and in oral statements, words such as “may”, “will”, “expect”, “anticipate”, “continue”, “estimate”, “project”, “believes” or similar ex 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. These forward-looking statements involve risks and uncertainties. Actual results may differ materially from those contemplated by the forward-looking statements due to, among other factors, the risks and uncertainties described in the section entitled “Risk Factors” in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2014, as well as the various factors described below:

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

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

We rely on access to both short- and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations. If we are not able to access capital at competitive rates, our ability to implement our business plans may be adversely affected.

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

We made a $10.0 million discretionary contribution to our defined benefit pension plan in January 2015. We could be required to contribute additional capital to the pension plan in the future if the market value of pension plan assets significantly declines, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

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

Declines in projected operating cash flows at any of our reporting units may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

The inability of our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and debt covenants and pay dividends to our shareholders could have an adverse effect on us.

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 realign our business mix through capital projects, acquisitions and dispositions may not be successful, which could result in poor financial performance.

We may, from time to time, sell assets to provide capital to fund investments in our electric utility business or for other corporate purposes, which could result in the recognition of a loss on the sale of any assets sold and other potential liabilities. The sale of any of our businesses could expose us to additional risks associated with indemnification obligations under the applicable sales agreements and any related disputes.

Our plans to grow and operate our nonutility businesses could be limited by state law.

Significant warranty claims and remediation costs in excess of amounts normally reserved for such items could adversely affect our results of operations and financial condition.

We are subject to risks associated with energy markets.

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

We rely on our information systems to conduct our business and failure to protect these systems against security breaches or cyber-attacks could adversely affect our business and results of operations. Additionally, if these systems fail or become unavailable for any significant period of time, our business could be harmed.

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 our shareholders or scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.

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

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.

Changes to regulation of generating plant emissions, including but not limited to carbon dioxide emissions, could affect OTP's operating costs and the costs of supplying electricity to its customers.

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

Our Plastics segment is highly dependent on a limited number of vendors for PVC resin, many of which are located in the Gulf Coast region of the United States, 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 segment.

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.

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At June 30, 2015 we had exposure to market risk associated with interest rates because we had $38.5 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.75% under our $150 million revolving credit facility, and OTP had $4.5 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.25% under its $170 million revolving credit facility.

All of our consolidated long-term debt outstanding on June 30, 2015 has fixed interest rates. 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.

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 companies in our Manufacturing segment are exposed to market risk related to changes in commodity prices for steel, aluminum and polystyrene (PS) and other plastics resins. The price and availability of these raw materials could affect the revenues and earnings of our Manufacturing segment.

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 volume 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.

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 sales. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity sales. Specific limits are determined by a counterparty’s financial strength. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor’s), Baa3 (Moody’s) or BBB- (Fitch). OTP had no exposure at June 30, 2015 to counterparties with investment grade or below investment grade credit ratings with respect to any of its forward energy contracts.

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, as amended (the Exchange Act)) as of June 30, 2015, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of June 30, 2015.

During the fiscal quarter ended June 30, 2015, there were no changes in the Company’s internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is the subject of various pending or threatened legal actions and proceedings in the ordinary course of its business. Such matters are subject to many uncertainties and to outcomes that are not predictable with assurance. The Company records a liability in its consolidated financial statements for costs related to claims, including future legal costs, settlements and judgments, where it has assessed that a loss is probable and an amount can be reasonably estimated. The Company believes the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on the Company’s consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

The Company is updating the risk factors set forth under Part I, Item 1A, “Risk Factors” on pages 27 through 33 of its Annual Report on Form 10-K for the year ended December 31, 2014, by revising the Electric segment risk factor related to changes to regulation of generating plant emissions, including but not limited to CO2 emissions, as a result of the U.S. Environmental Protection Agency (EPA) August 3, 2015 announcement of final emission guidelines for fossil fuel-fired power plants under Section 111(d) of the Clean Air Act.

Revised Risk Factor:

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

Existing or new laws or regulations passed or issued by federal or state authorities addressing climate change or reductions of GHG emissions, such as mandated levels of renewable generation, mandatory reductions in CO_2 emission levels, taxes on CO_2 emissions or cap and trade regimes, could require us to incur significant new costs, which 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. Debate continues in Congress on the direction and scope of U.S. policy on climate change and regulation of GHGs. Congress has considered but has not adopted GHG legislation which would require a reduction in GHG emissions and there is no legislation under active consideration at this time. The likelihood of any federal mandatory CO_2 emissions reduction program being adopted by Congress in the near future, and the specific requirements of any such program, are uncertain.

In 2014, the EPA published proposed standards of performance for CO_2 emissions from new fossil fuel-fired power plants, proposed CO_2 emission guidelines for existing fossil fuel-fired power plants and proposed CO_2 emission standards for reconstructed and modified fossil fuel-fired power plants, essentially requiring that such plants install modern technology, when modifying or reconstructing, to reduce their emissions. The EPA announced final rules for each of these proposals on August 3, 2015. For existing sources, states are required to develop and submit plans, either individually or with other states, spelling out how they will achieve the individualized, reduced CO_2 emission rates that the EPA has identified. Those state plans are due by September 6, 2016, or at a minimum states must make an initial submittal by that date in order to receive a two-year extension, such that final state plans are due by September 6, 2018. OTP is currently assessing the potential impact of the final rules on existing affected sources of CO_2 emissions at OTP.

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

The Company does not have a publicly announced stock repurchase program. The following table shows common shares that were surrendered to the Company by employees to pay taxes in connection with shares issued or vested for incentive awards in April 2015 under the Company's 1999 and 2014 Stock Incentive Plans:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
April 2015	5,706	$ 31.845
May 2015	--	--
June 2015	--	--
Total	5,706	

Item 6. Exhibits

10.1	Otter Tail Corporation Executive Severance Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K filed by Otter Tail Corporation on April 15, 2015).
10.2	Distribution Agreement Dated May 11, 2015 between Otter Tail Corporation and J.P. Morgan Securities LLC (incorporated by reference to Exhibit 1.1 to the Form 8-K filed by Otter Tail Corporation on May 11, 2015).
10.3	Big Stone South – Ellendale Project Ownership Agreement dated as of June 12, 2015 between Otter Tail Power Company, a wholly owned subsidiary of Otter Tail Corporation, and Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.*
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Financial statements from the Quarterly Report on Form 10-Q of Otter Tail Corporation for the quarter ended June 30, 2015, formatted in Extensible Business Reporting Language: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Cash Flows and (v) the Condensed Notes to Consolidated Financial Statements.

* Confidential information has been omitted from this Exhibit and filed separately with the Commission pursuant to a confidential treatment request under Rule 24b-2.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

OTTER TAIL CORPORATION

By: /s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer
(Chief Financial Officer/Authorized Officer)

Dated: August 10, 2015

EXHIBIT INDEX

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