Otter Tail Corp
Form 10-Q
May 10, 2011

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2011

OR

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

For the transition period from to

Commission file number 0-53713

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

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

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

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

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

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

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

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

Large accelerated filer X	Accelerated filer __
Non-accelerated filer __ (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 X

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

April 30, 2011 – 36,058,873 Common Shares ($5 par value)

OTTER TAIL CORPORATION

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands)		March 31, 2011		December 31, 2010
ASSETS				
Current Assets				
Cash and Cash Equivalents	$	186	$	--
Accounts Receivable:				
Trade—Net		152,509		125,308
Other		15,935		19,399
Inventories		81,141		79,354
Deferred Income Taxes		12,206		11,068
Accrued Utility and Cost-of-Energy Revenues		13,090		16,323
Costs and Estimated Earnings in Excess of Billings		66,269		67,352
Income Taxes Receivable		4,307		4,146
Other		25,503		21,646
Assets of Discontinued Operations		90,267		90,684
Total Current Assets		461,413		435,280
Investments		9,794		9,708
Other Assets		28,233		27,356
Goodwill		69,742		69,742
Other Intangibles—Net		16,056		16,280
Deferred Debits				
Unamortized Debt Expense		6,656		6,444
Regulatory Assets		117,485		127,766
Total Deferred Debits		124,141		134,210
Plant				
Electric Plant in Service		1,333,125		1,332,974
Nonelectric Operations		355,842		340,907
Construction Work in Progress		51,808		42,031
Total Gross Plant		1,740,775		1,715,912
Less Accumulated Depreciation and Amortization		653,173		637,933
Net Plant		1,087,602		1,077,979
Total Assets	$	1,796,981	$	1,770,555

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)	March 31, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$116,976	$79,490
Current Maturities of Long-Term Debt	683	604
Accounts Payable	109,834	117,911
Accrued Salaries and Wages	16,379	20,252
Accrued Taxes	11,642	11,957
Derivative Liabilities	19,633	17,991
Other Accrued Liabilities	11,142	9,546
Liabilities of Discontinued Operations	18,961	19,026
Total Current Liabilities	305,250	276,777
Pensions Benefit Liability	74,506	73,538
Other Postretirement Benefits Liability	42,991	42,372
Other Noncurrent Liabilities	21,182	21,043
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	163,318	162,208
Deferred Tax Credits	44,199	44,945
Regulatory Liabilities	67,162	66,416
Other	469	556
Total Deferred Credits	275,148	274,125
Capitalization		
Long-Term Debt, Net of Current Maturities	436,064	434,812
Class B Stock Options of Subsidiary	525	525
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2011 and 2010 – 155,000 Shares	15,500	15,500
Cumulative Preference Shares – Authorized 1,000,000 Shares Without Par Value; Outstanding - None	--	--
Common Shares, Par Value $5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2011—36,002,739 Shares; 2010—36,002,739 Shares	180,014	180,014
Premium on Common Shares	251,505	251,919
Retained Earnings	193,244	198,443

Accumulated Other Comprehensive Income	1,052	1,487
Total Common Equity	625,815	631,863
Total Capitalization	1,077,904	1,082,700
Total Liabilities and Equity	$1,796,981	$1,770,555

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended March 31, 2011	2010
Operating Revenues		
Electric	$91,525	$91,381
Nonelectric	195,156	152,305
Total Operating Revenues	286,681	243,686
Operating Expenses		
Production Fuel - Electric	19,577	20,909
Purchased Power - Electric System Use	12,377	12,056
Electric Operation and Maintenance Expenses	28,708	28,466
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	155,709	117,484
Other Nonelectric Expenses	35,626	29,738
Depreciation and Amortization	19,113	18,584
Property Taxes - Electric	2,409	2,474
Total Operating Expenses	273,519	229,711
Operating Income	13,162	13,975
Other Income	675	13
Interest Charges	9,489	9,022
Income from Continuing Operations Before Income Taxes	4,348	4,966
Income Taxes – Continuing Operations	414	1,653
Income from Continuing Operations	3,934	3,313
Income from Discontinued Operations net of Income Taxes of $1,112 and $727, respectively	1,762	1,404
Net Income	5,696	4,717
Preferred Dividend Requirements	184	184
Earnings Available for Common Shares	$5,512	$4,533
Average Number of Common Shares Outstanding—Basic	35,876,853	35,720,571
Average Number of Common Shares Outstanding—Diluted	36,081,426	35,939,759
Basic Earnings Per Common Share:		
Continuing Operations (net of preferred dividend requirement)	$0.10	$0.09
Discontinued Operations	0.05	0.04
	0.15	0.13
Diluted Earnings Per Common Share:		
Continuing Operations (net of preferred dividend requirement)	$0.10	$0.09
Discontinued Operations	0.05	0.04
	0.15	0.13
Dividends Per Common Share	$0.2975	$0.2975

See accompanying notes to consolidated financial statements.

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

(in thousands)	Three Months Ended March 31, 2011	2010
Cash Flows from Operating Activities		
Net Income	$5,696	$4,717
Adjustments to Reconcile Net Income to Net Cash (Used in) Provided by Operating Activities:		
Income from Discontinued Operations	(1,762)	(1,404)
Depreciation and Amortization	19,113	18,584
Deferred Tax Credits	(659)	(679)
Deferred Income Taxes	4,099	6,863
Change in Deferred Debits and Other Assets	6,266	15
Change in Noncurrent Liabilities and Deferred Credits	90	2,346
Allowance for Equity (Other) Funds Used During Construction	(116)	--
Change in Derivatives Net of Regulatory Deferral	(59)	(1,622)
Stock Compensation Expense – Equity Awards	452	610
Other—Net	(120)	(52)
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(23,737)	(20,890)
Change in Inventories	(1,787)	(8,345)
Change in Other Current Assets	(747)	(23,425)
Change in Payables and Other Current Liabilities	(3,869)	2,837
Change in Interest Payable and Income Taxes Receivable/Payable	1,306	(710)
Net Cash Provided by (Used in) Continuing Operations	4,166	(21,155)
Net Cash Provided by (Used in) Discontinued Operations	2,795	(1,585)
Net Cash Provided by (Used in) Operating Activities	6,961	(22,740)
Cash Flows from Investing Activities		
Capital Expenditures	(23,981)	(17,687)
Proceeds from Disposal of Noncurrent Assets	984	619
Net (Increase) in Other Investments	(598)	(1,001)
Net Cash Used in Investing Activities - Continuing Operations	(23,595)	(18,069)
Net Cash Provided by Investing Activities - Discontinued Operations	137	11
Net Cash Used in Investing Activities	(23,458)	(18,058)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	(10,030)	244
Net Short-Term Borrowings	37,486	102,914
Proceeds from Issuance of Common Stock	--	55
Common Stock Issuance Expenses	--	(79)
Payments for Retirement of Common Stock	--	(262)
Proceeds from Issuance of Long-Term Debt	1,500	95
Short-Term and Long-Term Debt Issuance Expenses	(686)	(87)
Payments for Retirement of Long-Term Debt	(170)	(58,350)
Dividends Paid and Other Distributions	(11,041)	(10,938)
Net Cash Provided by Financing Activities - Continuing Operations	17,059	33,592
Net Cash (Used in) Provided by Financing Activities - Discontinued Operations	(88)	3,007
Net Cash Provided by Financing Activities	16,971	36,599

Cash and Cash Equivalents at Beginning of Period – Discontinued Operations	--	(609)
Effect of Foreign Exchange Rate Fluctuations on Cash – Discontinued Operations	(288)	(233)
Net Change in Cash and Cash Equivalents	186	(5,041)
Cash and Cash Equivalents at Beginning of Period	--	5,041
Cash and Cash Equivalents at End of Period	$186	$--

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated financial statements for the periods presented. The consolidated financial statements and notes thereto should be read in conjunction with the consolidated financial statements and notes as of and for the years ended December 31, 2010, 2009 and 2008 included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2010. Because of seasonal and other factors, the earnings for the three months ended March 31, 2011 should not be taken as an indication of earnings for all or any part of the balance of the year.

The following notes are numbered to correspond to numbers of the notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

1. Summary of Significant Accounting Policies

Revenue Recognition
Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, and the price is fixed or determinable. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as Otter Tail Power Company's (OTP) forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with Accounting Standards Codification (ASC) 815-10-45-9. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

For the Company's operating companies recognizing revenue on certain products when shipped, those operating companies have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

Some of the operating businesses in the Company's Wind Energy, Manufacturing and Construction segments enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The Company's consolidated revenues recorded under the percentage-of-completion method were 28.9% for the three months ended March 31, 2011 and 23.9% for the three months ended March 31, 2010. The method used to determine the progress of completion is based on the ratio of labor hours incurred to total estimated labor hours at the Company's wind tower manufacturer and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized.

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

(in thousands)	March 31, 2011	December 31, 2010
Costs Incurred on Uncompleted Contracts	$406,085	$460,125
Less Billings to Date	(365,443)	(430,471)

Plus Estimated Earnings Recognized	20,628	31,231
	$61,270	$60,885

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

(in thousands)	March 31, 2011	December 31, 2010
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$66,269	$67,352
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(4,999)	(6,467)
	$61,270	$60,885

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI), the Company's wind tower manufacturer, were $56,178,000 as of March 31, 2011 and $58,990,000 as of December 31, 2010. This amount is related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

Retainage

Accounts Receivable include amounts billed by the Company's subsidiaries under contracts that have been retained by customers pending project completion of $11,638,000 on March 31, 2011 and $11,848,000 on December 31, 2010.

Sales of Receivables

DMI is a party to a $40 million receivables purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement, originally scheduled to expire in March 2011, was extended for one year by DMI in February 2011. The discount rate for the one-year extension was increased to 3-month LIBOR plus 4%. Accounts receivable sold totaled $19,048,000 in the first three months of 2011 compared with $10,800,000 in the first three months of 2010. Discounts, fees and commissions charged to operating expenses in the consolidated statements of income were $118,000 in the first three months of 2011 compared with $32,000 in the first three months of 2010. In compliance with guidance under ASC 860-20, Sales of Financial Assets, sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows.

Supplemental Disclosures of Cash Flow Information

(in thousands)	Three Months Ended March 31, 2011	2010
Increases in Accounts Payable Related to Capital Expenditures	$1,047	$41

Fair Value Measurements

The Company follows ASC 820, Fair Value Measurements and Disclosures, for recurring fair value measurements. ASC 820 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. ASC 820-10-35 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

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

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

Level 3 – Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

The following table presents, for each of these hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of March 31, 2011 and December 31, 2010:

March 31, 2011 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds and Cash	$699	$--	
Forward Gasoline Purchase Contracts	249		
Forward Energy Contracts		5,480	
Regulatory Asset – Deferred Mark-to-Market Losses on Forward Energy Contracts		15,027	
Investments of Captive Insurance Company:			
Corporate Debt Securities	8,692		
Total Assets	$9,640	$20,507	
Liabilities:			
Forward Energy Contracts	$--	$19,633	
Regulatory Liability – Deferred Mark-to-Market Gains on Forward Energy Contracts		242	
Total Liabilities	$--	$19,875	

December 31, 2010 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds and Cash	$800	$--	
Forward Gasoline Purchase Contracts	58		
Forward Energy Contracts		6,875	
Regulatory Asset – Deferred Mark-to-Market Losses on Forward Energy Contracts		12,054	
Investments of Captive Insurance Company:			
Corporate Debt Securities	8,467		
Total Assets	$9,325	$18,929	
Liabilities:			
Forward Energy Contracts	$--	$17,991	
Regulatory Liability – Deferred Mark-to-Market Gains on Forward Energy Contracts		175	
Total Liabilities	$--	$18,166	

Reclassifications and Changes to Presentation

The Company's consolidated balance sheet as of December 31, 2010, and consolidated income statement and consolidated statement of cash flows for the three months ended March 31, 2010 reflect the reclassifications of the assets and liabilities, operating results and cash flows of Idaho Pacific Holdings, Inc. (IPH) to discontinued operations as a result of a second quarter 2011 decision to sell IPH. The Company reached an agreement to sell IPH on May 6, 2011. The reclassifications had no impact on the Company's total assets, consolidated net income or cash flows for the three months ended March 31, 2010.

In 2011 management reported Minnesota Conservation Improvement Program (MNCIP) incentives in Operating Revenues – Electric rather than Other Income as they had been classified prior to 2011. The Company has corrected this classification resulting in an increase in Operating Revenues and Operating Income and a decrease in Other Income of $362,000 for the three months ended March 31, 2010. The correction had no impact on the Company's net income, total assets, or operating cash flows for the three months ended March 31, 2010.

Inventories

Inventories consist of the following:

(in thousands)	March 31, 2011	December 31, 2010
Finished Goods	$30,938	$29,113
Work in Process	8,219	7,171
Raw Material, Fuel and Supplies	41,984	43,070
Total Inventories	$81,141	$79,354

Goodwill

The following table summarizes changes to goodwill by business segment during 2011:

(in thousands)	Balance December 31, 2010	Impairments	Balance (net of impairments) December 31, 2010	Adjustments to Goodwill in 2011	Balance (net of impairments) March 31, 2011
Electric	$240	$(240)	$--	$--	$--
Wind Energy	6,959	--	6,959	--	6,959
Manufacturing	24,445	(12,259)	12,186	--	12,186
Construction	7,630	--	7,630	--	7,630
Plastics	19,302	--	19,302	--	19,302
Health Services	23,665	--	23,665	--	23,665
Total	$82,241	$(12,499)	$69,742	$--	$69,742

Other Intangible Assets

The following table summarizes the components of the Company's intangible assets at March 31, 2011 and December 31, 2010:

March 31, 2011 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Customer Relationships	$ 16,811	$ 2,599	$ 14,212	15 – 25 years
Covenants Not to Compete	1,704	1,688	16	3 – 5 years
Other Intangible Assets Including Contracts	930	892	38	5 – 30 years
Total	$ 19,445	$ 5,179	$ 14,266	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 1,790	$ --	$ 1,790	
December 31, 2010 (in thousands)				
Amortized Intangible Assets:				
Customer Relationships	$ 16,811	$ 2,388	$ 14,423	15 – 25 years
Covenants Not to Compete	1,704	1,676	28	3 – 5 years
Other Intangible Assets Including Contracts	930	891	39	5 – 30 years
Total	$ 19,445	$ 4,955	$ 14,490	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 1,790	$ --	$ 1,790	

The amortization expense for these intangible assets was $224,000 for the three months ended March 31, 2011 compared with $283,000 for the three months ended March 31, 2010. The estimated annual amortization expense for these intangible assets for the next five years is $874,000 for 2011, $895,000 for 2012, $931,000 for 2013, $931,000 for 2014 and $931,000 for 2015.

Comprehensive Income

	Three Months Ended March 31,	
(in thousands)	2011	2010
Net Income	$5,696	$4,717
Other Comprehensive Income (Loss) (net-of-tax):		
Foreign Currency Translation Gain	445	488
Amortization of Unrecognized Losses and Costs Related to Postretirement Benefit Programs	(870)	105
Unrealized (Loss) Gain on Available-for-Sale Securities	(10)	39
Total Other Comprehensive Income (Loss)	(435)	632
Total Comprehensive Income	$5,261	$5,349

2. Segment Information

The Company's businesses have been classified into six 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 reach customers in all 50 states and international markets. The six segments are: Electric, Wind Energy, Manufacturing, Construction, Plastics and Health Services.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is an active wholesale participant in the Midwest Independent Transmission System Operator (MISO) markets. OTP's operations have been the Company's primary business since 1907. Additionally, the electric segment includes Otter Tail Energy Services Company (OTESCO), which provides technical and engineering services, wind farm site development and energy efficient lighting primarily in North Dakota and Minnesota.

Wind Energy consists of two businesses: a steel fabrication company primarily involved in the production of wind towers sold in the United States and Canada, with manufacturing facilities in North Dakota, Oklahoma and Ontario, Canada, and a trucking company headquartered in West Fargo, North Dakota, specializing in flatbed and heavy-haul services and operating in 49 states and six Canadian provinces. Prior to the realignment of the Company's business segments, the wind tower production company was included in Manufacturing and the trucking company was included in Other Business Operations.

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

Construction consists of businesses involved in residential, commercial and industrial electric contracting and construction of fiber optic and electric distribution systems, water, wastewater and HVAC systems primarily in the central United States. Construction operations were included in Other Business Operations prior to the realignment of the Company's business segments.

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

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

Food Ingredient Processing is no longer a reportable segment as a result of the sale of IPH on May 6, 2011. The results of operations, financial position and cash flows of IPH are reported as discontinued operations in the Company's consolidated financial statements.

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

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

The Company had no single external customer that accounted for 10% or more of the Company's consolidated revenues in 2010. Substantially all of the Company's long-lived assets are within the United States except for a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

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

	Three Months Ended March 31, 2011	2010
United States of America	98.7 %	97.2 %
Canada	1.2 %	2.7 %
All Other Countries (none greater than 1%)	0.1 %	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 three month periods ended March 31, 2011 and 2010 and total assets by business segment as of March 31, 2011 and December 31, 2010 are presented in the following tables:

Operating Revenue

(in thousands)	Three Months Ended March 31, 2011	2010
Electric	$91,596	$91,452
Wind Energy	61,597	49,398
Manufacturing	56,313	38,031
Construction	37,515	17,774
Plastics	18,478	23,087
Health Services	22,495	25,171
Corporate Revenues and Intersegment Eliminations	(1,313)	(1,227)
Total	$286,681	$243,686

Interest Expense

(in thousands)	Three Months Ended March 31, 2011	2010
Electric	$5,088	$5,270
Wind Energy	1,914	1,321
Manufacturing	1,306	1,247
Construction	220	118
Plastics	363	363
Health Services	399	245
Corporate and Intersegment Eliminations	199	458

Total	$9,489	$9,022

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Income Taxes

(in thousands)	Three Months Ended March 31, 2011	2010
Electric	$2,600	$4,834
Wind Energy	(2,798)	(7)
Manufacturing	1,530	(618)
Construction	(210)	(1,001)
Plastics	(241)	494
Health Services	409	(432)
Corporate	(876)	(1,617)
Total	$414	$1,653

Earnings Available for Common Shares

(in thousands)	Three Months Ended March 31, 2011	2010
Electric	$11,142	$7,491
Wind Energy	(8,111)	33
Manufacturing	2,267	(735)
Construction	(325)	(1,489)
Plastics	(374)	781
Health Services	572	(691)
Corporate	(1,421)	(2,261)
Discontinued Operations	1,762	1,404
Total	$5,512	$4,533

Total Assets

(in thousands)	March 31, 2011	December 31, 2010
Electric	$1,094,549	$1,106,261
Wind Energy	195,574	175,852
Manufacturing	153,971	144,272
Construction	64,500	60,978
Plastics	76,993	73,508
Health Services	74,180	75,898
Corporate	46,947	43,102
Discontinued Operations	90,267	90,684
Total	$1,796,981	$1,770,555

3. Rate and Regulatory Matters

Minnesota

2010 General Rate Case Filing—OTP filed a general rate case on April 2, 2010 requesting an 8.01% increase with a 3.8% interim rate request. On May 27, 2010, the Minnesota Public Utilities Commission (MPUC) issued an order accepting the filing, suspending rates and setting interim rates. The MPUC approved a 3.8% interim rate increase to be effective with customer usage on and after June 1, 2010. The MPUC held a hearing to decide on the issues in the rate case on March 25, 2011 and issued a written order on April 25, 2011. OTP calculated the impact of its understanding of the MPUC's oral decision prior to receiving the written order and estimated there would be an interim rate refund of approximately $3.8 million. Based on its estimate, OTP accrued a $2.3 million refund liability in the first quarter of 2011 related to revenue that had been billed under interim rates from June 1, 2010 through March 31, 2011. OTP expects the refund to be distributed to Minnesota customers during the fourth quarter of 2011. The MPUC’s written order included recovery of Big Stone II costs over five years (see discussion below), inclusion of wind farm assets in base rates, transfer of cost recovery from the MNCIP tracker to base rates, and inclusion of fuel costs and revenues related to asset-based wholesale sales of electricity in the Minnesota fuel clause adjustment (FCA). Pursuant to the order, OTP’s allowed rate of return on rate base will increase from 8.33% to 8.61% and its allowed rate of return on equity will increase from 10.43% to 10.74%. OTP's rates of return will be based on a capital structure of 48.28% long term debt and 51.72% common equity. OTP intends to request reconsideration on certain issues and the MPUC has 60 days to reconsider its order after requests for reconsideration are submitted.

OTP has a regulatory asset of $4.8 million for revenues that are eligible for recovery through the Minnesota Renewable Resource Adjustment (MNRRA) rider that have not been billed to Minnesota customers as of March 31, 2011. Except for the balance of this regulatory asset, the recovery of MNRRA costs will be moved to base rates late in 2011 as part of the MPUC’s order in OTP’s 2010 general rate case.

In OTP’s 2010 general rate case, the MPUC approved the transfer of transmission costs currently being recovered through OTP’s Minnesota Transmission Cost Recovery (TCR) rider to recovery in base rates. The transmission investments will continue to be recovered through OTP’s Minnesota TCR rider rate until final rates go into effect at the conclusion of the general rate case. OTP filed a request for an update to its Minnesota TCR rider rate on October 5, 2010. Comments and reply comments have been filed but the MPUC has not yet scheduled a hearing on the request.

North Dakota

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. OTP requested recovery of such costs in its general rate case filed in November 2008 and was granted recovery of such costs by the North Dakota Public Service Commission (NDPSC) in its November 25, 2009 order. OTP filed a request for an initial North Dakota TCR rider with the NDPSC on April 29, 2011.

South Dakota

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

A joint motion for approval of a settlement stipulation allowing the inclusion of OTP’s Luverne Wind Farm assets in its South Dakota rate base was filed and brought before the SDPUC on April 19, 2011. Final rates will be effective as of June 1, 2011. Interim rates will remain in effect until final rates begin and there will not be any interim rate refund because interim rates are the same amount as the final rates. In the oral decision made by the SDPUC, the SDPUC approved a revenue increase of $643,000. OTP’s allowed rate of return on rate base in South Dakota will be 8.50% based on a capital structure of 47.0% long term debt and 53.0% common equity.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. OTP submitted a request for an initial South Dakota TCR rider to the SDPUC on November 5, 2010. The South Dakota TCR request is scheduled for hearing on May 17, 2011.

Capacity Expansion 2020 (CapX2020)

Fargo–Monticello 345 kiloVolt (kV) Project, Brookings–Southeast Twin Cities 345 kV Project and Twin Cities–LaCrosse 345 kV Project—On April 16, 2009 the MPUC approved the Certificates of Need (CONs) for the three 345 kV Group 1 CapX2020 line projects (Fargo-Monticello, Brookings-Southeast Twin Cities, and Twin Cities-LaCrosse).

The route permit application for the Monticello to St. Cloud portion of the Fargo project was filed in April 2009. The MPUC approved the route permit application and issued a written order on July 12, 2010. Required permits from the Minnesota Department of Transportation, Minnesota Department of Natural Resources and the U.S. Army Corps of Engineers were received in 2010. A Transmission Capacity Exchange Agreement, allocating transmission capacity rights to owners across the Monticello to St. Cloud portion of the project, was accepted by the Federal Energy Regulatory Commission (FERC) in the third quarter of 2010.

The Minnesota route permit application for the St. Cloud to Fargo portion of the Fargo project was filed on October 1, 2009. The MPUC is expected to make a determination on the route permit application in the second quarter of 2011. Minnesota State Environmental Impact Statement (EIS) scoping meetings were held in September 2010 and public hearings were held in November 2010. On October 8, 2010, OTP submitted its application for a Certificate of Public Convenience and Necessity (CPCN) from the NDPSC for the North Dakota portion of the Fargo–Monticello 345 kV project. The NDPSC approved the CPCN in January 2011. The application for North Dakota Certificate of Corridor Compatibility was filed on December 30, 2010.

The Minnesota route permit application for the Brookings project was filed in the fourth quarter of 2008. On July 15, 2010 the MPUC voted to approve most of the Brookings route permit application. On September 15, 2010 the MPUC approved a route permit for five of six project line segments, with the exception of the line segment that crosses the Minnesota River. Additional Evidentiary Hearings were held regarding the line segment crossing the Minnesota River, and the Administrative Law Judge issued a report in December 2010. The MPUC approved the final line segment for the project on February 3, 2011.

An application for a South Dakota facility route permit was filed with the SDPUC on November 22, 2010. The SDPUC conducted a public hearing in January 2011 and a South Dakota route permit is expected to be approved in the second quarter of 2011.

Bemidji–Grand Rapids 230 kV Project—OTP serves as the lead utility for the CapX2020 Bemidji-Grand Rapids 230-kV project, which has an expected in-service date of late 2012 or early 2013. The MPUC approved the CON for this project on July 9, 2009. A route permit application was filed with the MPUC in the second quarter of 2008 for the Bemidji-Grand Rapids project. On October 28, 2010 the MPUC approved the route permit application for the project. The joint state and federal EIS was published by the federal agencies on September 7, 2010, and the project's Transmission Capacity Exchange Agreement was accepted and approved by the FERC in the third quarter of 2010. On March 25, 2011, the Leech Lake Band of Ojibwe (LLBO) submitted a petition to MPUC, requesting the revocation or suspension of the project's route permit. The request is based on the LLBO's allegation that it has jurisdiction to require the project to obtain its permission to cross through the historical boundaries of the LLBO Reservation. The owners of the Bemidji project, including OTP, have filed reply comments in opposition to the LLBO's request. On April 25, 2011, the Bemidji project owners filed a declaratory judgment complaint in the U.S. District Court for Minnesota against the LLBO. The federal court action seeks a declaratory judgment that no consent from the LLBO is required for the Project through the LLBO reservation boundaries since the project is located exclusively on non LLBO lands.

CapX2020 Request for Advance Determination of Prudence—On October 5, 2009 OTP filed an application for an advance determination of prudence with the NDPSC for its proposed participation in three of the four Group 1 projects (Fargo-Monticello, Brookings-Southeast Twin Cities, and Bemidji-Grand Rapids). An administrative law judge conducted an evidentiary hearing on the application in May 2010. On October 6, 2010 the NDPSC adopted an order approving a settlement between OTP and intervener NDPSC advocacy staff, and issuing an advance determination of prudence to OTP for participation in the three Group 1 projects. The order is subject to a number of terms and conditions in addition to the settlement agreement, including the provision of additional information on the eventual resolution of cost allocation issues relevant to the Brookings-Southeast Twin Cities project and its associated impact on North Dakota. On April 29, 2011, OTP filed its compliance filing with the NDPSC, seeking the NDPSC's determination of continued prudence for OTP's investment in the Brookings Project.

Big Stone Air Quality Control System

The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant is subject to Best Available Retrofit Technology (BART) requirements of the Clean Air Act (CAA), based on air dispersion modeling indicating that Big Stone's emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan. Under the U.S. Environmental Protection Agency's (EPA) regional haze regulations, South Dakota has developed and submitted its implementation plan and associated implementing rules to EPA on January 11, 2011. Under the South Dakota Implementation Plan, and its implementing rules that became effective in December 2010, the Big Stone Plant must install and operate a new BART compliant air quality control system to reduce emissions as expeditiously as practicable, but no later than five years after the EPA's approval of South Dakota's implementation plan. Although studies and evaluations are continuing, the current project cost is estimated to be approximately $490 million (OTP's share would be $264 million). On January 14, 2011 OTP filed a petition asking the MPUC for advance determination of prudence for the design, construction and operation of the BART compliant air quality control system at Big Stone Plant attributable to serving OTP's Minnesota customers. The Big Stone Plant is currently operating within all presently applicable federal and state air quality and emission standards.

Big Stone II Project

On June 30, 2005 OTP and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. On September 11, 2009 OTP announced its withdrawal—both as a participating utility and as the project's lead developer—from Big Stone II, due to a number of factors. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project.

OTP requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010. In a written order issued on April 25, 2011, the MPUC authorized recovery of the Minnesota portion of Big Stone II generation development costs from Minnesota ratepayers over a 60-month recovery period expected to begin in October 2011. The amount of Big Stone II generation costs incurred by OTP that were deemed recoverable from Minnesota ratepayers (which excludes $3,246,000 of project transmission-related costs) was $3,199,000. Because the MPUC denied OTP an investment return on these deferred costs over the 60-month recovery period, the recoverable amount has been discounted to its present value of $2,758,000, in accordance with ASC 980, Regulated Operations, accounting requirements.

On December 30, 2010 OTP filed a request for an extension of the Minnesota Route Permit for the Big Stone transmission facilities. The request asks to extend the deadline for filing a CON for these transmission facilities until March 17, 2013. The April 25, 2011 MPUC order instructed OTP to transfer the $3,246,000 Minnesota share of Big Stone II transmission costs to Construction Work in Progress (CWIP) and to create a tracker account through which any over or under recoveries could be accumulated for refund or recovery determination in future rate cases as a regulatory liability or asset. If determined eligible for recovery under the FERC-approved MISO regional transmission tariff, the Minnesota portion of Big Stone II transmission costs and accumulated Allowance for Funds Used During Construction (AFUDC) will receive rate base treatment and recovery through the FERC-approved MISO regional transmission rates. Any amounts over or under collected through MISO rates will be reflected in the tracker account.

OTP requested recovery of the South Dakota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in South Dakota on August 20, 2010. In the first quarter of 2011, the SDPUC approved recovery of the South Dakota portion of Big Stone II generation development costs totaling approximately $1.0 million from South Dakota ratepayers over a ten-year period beginning in February 2011 with the implementation of interim rates. OTP will be allowed to earn a return on the amount subject to recovery over the ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted. OTP transferred the remaining Big Stone II transmission costs to CWIP, with such costs subject to AFUDC and recovery in future FERC-approved MISO rates or retail rates.

4. Regulatory Assets and Liabilities

As a regulated entity OTP accounts for the financial effects of regulation in accordance with ASC 980, Regulated Operations. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheet:

(in thousands)	March 31, 2011	December 31, 2010	Recovery/ Refund Period
Regulatory Assets - Current:			
Accrued Cost-of-Energy Revenue	$(68)	$2,387	17 months
Regulatory Assets – Long Term:			
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$71,628	$74,156	see below
Deferred Marked-to-Market Losses	15,027	12,054	48 months
Deferred Conservation Improvement Program Costs & Accrued Incentives	7,289	6,655	27 months
Minnesota Renewable Resource Rider Accrued Revenues	4,836	6,834	36 months
Big Stone II Unrecovered Project Costs – North Dakota	3,052	3,460	28 months
Debt Reacquisition Premiums	2,858	3,107	258 months
Big Stone II Unrecovered Project Costs – Minnesota	2,758	6,445	66 months
Deferred Income Taxes	2,453	5,785	asset lives
Accumulated ARO Accretion/Depreciation Adjustment	2,325	2,218	asset lives
General Rate Case Recoverable Expenses	1,451	1,773	35 months
North Dakota Renewable Resource Rider Accrued Revenues	1,272	2,415	33 months
Big Stone II Unrecovered Project Costs – South Dakota	987	1,419	118 months
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	624	717	20 months
South Dakota – Asset-Based Margin Sharing Shortfall	494	501	11 months
Minnesota Transmission Rider Accrued Revenues	252	34	21 months
Deferred Holding Company Formation Costs	179	193	39 months
Total Regulatory Assets – Long Term	$117,485	$127,766	
Regulatory Liabilities:			
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$62,132	$61,740	asset lives
Deferred Income Taxes	4,148	4,289	asset lives
Minnesota Transmission Rider Accrued Refund	436	--	see below
Deferred Marked-to-Market Gains	242	175	53 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	127	128	273 months
South Dakota – Nonasset-Based Margin Sharing Excess	77	84	21 months
Total Regulatory Liabilities	$67,162	$66,416	
Net Regulatory Asset Position	$50,255	$63,737	

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

All Deferred Marked-to-Market Gains and Losses recorded as of March 31, 2011 are related to forward purchases of energy scheduled for delivery through August 2015.

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

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 through 2011 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of March 31, 2011.

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

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 258 months.

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

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

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

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of March 31, 2011.

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

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

Minnesota Transmission Rider Accrued Revenues are expected to be recovered from Minnesota retail electric customers over 12 months beginning in January 2012.

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

No schedule has been set for the return of the March 31, 2011 Minnesota Transmission Rider Accrued Refund balance.

South Dakota – Nonasset-Based Margin Sharing Excess represents 25% of OTP’s South Dakota share of actual profit margins on nonasset-based wholesale sales of electricity. The excess margins accumulated annually will be subject to refund through future retail rate adjustments in South Dakota in the following year.

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

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5. Forward Contracts Classified as Derivatives

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

As of March 31, 2011 OTP had recognized, on a pretax basis, $632,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in ASC 820-10-35.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of March 31, 2011 and December 31, 2010, and the change in the Company's consolidated balance sheet position from December 31, 2010 to March 31, 2011:

(in thousands)	March 31, 2011	December 31, 2010
Current Asset – Marked-to-Market Gain	$5,480	$6,875
Regulatory Asset – Deferred Marked-to-Market Loss	15,027	12,054
Total Assets	20,507	18,929
Current Liability – Marked-to-Market Loss	(19,633)	(17,991)
Regulatory Liability – Deferred Marked-to-Market Gain	(242)	(175)
Total Liabilities	(19,875)	(18,166)
Net Fair Value of Marked-to-Market Energy Contracts	$632	$763

(in thousands)	Year-to-Date March 31, 2011
Fair Value at Beginning of Year	$763
Less: Amounts Realized on Contracts Entered into in 2009 and Settled in 2011	(79)
Amounts Realized on Contracts Entered into in 2010 and Settled in 2011	(17)
Changes in Fair Value of Contracts Entered into in 2009 in 2011	--
Changes in Fair Value of Contracts Entered into in 2010 in 2011	(32)
Net Fair Value of Contracts Entered into in 2009 and 2010 at End of Period	635
Changes in Fair Value of Contracts Entered into in 2011	(3)

Net Fair Value End of Period	$632

The $632,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on March 31, 2011 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	2nd Quarter 2011	3rd Quarter 2011	4th Quarter 2011	2012	Total
Net Gain	$99	$109	$103	$321	$632

Realized and unrealized net (losses)/gains on forward energy contracts of ($8,000) for the three months ended March 31, 2011 and $1,825,000 for the three months ended March 31, 2010 are included in electric operating revenues on the Company's consolidated statements of income.

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

OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of March 31, 2011 was $378,000. As of March 31, 2011 OTP had a net credit risk exposure of $661,000 from eight counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. OTP had no exposure at March 31, 2011 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The $661,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after March 31, 2011. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $250,000 on certain OTP derivative energy contracts included in the $19,633,000 derivative liability on March 31, 2011 are covered by deposited funds. Certain other 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. The aggregate fair value of all forward energy derivative contracts with credit-risk-related contingent features that were in a liability position on March 31, 2011 was $5,381,000, for which OTP had posted $5,131,000 as collateral in the form of offsetting gain positions on other contracts with its counterparties under master netting agreements. If the credit-risk-related contingent features underlying these agreements had been triggered on March 31, 2011, OTP would have been required to provide $0 in additional cash to its counterparties. The remaining derivative liability balance of $14,252,000 relates to mark-to-market losses on contracts that have no ratings triggers or deposit requirements.

OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2010 was $585,000. As of December 31, 2010 OTP had a net credit risk exposure of $1,129,000 from four counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2010 to counterparties with credit ratings below investment grade. The $1,129,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2010. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $427,000 on certain OTP derivative energy contracts included in the $17,991,000 derivative liability on December 31, 2010 are covered by deposited funds. Certain other 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. The aggregate fair value of all forward energy derivative contracts with credit-risk-related contingent features that were in a liability position on December 31, 2010 was $10,904,000, for which OTP had posted $6,219,000 as collateral in the form of offsetting gain positions on other contracts with its counterparties under master netting agreements. If the credit-risk-related contingent features underlying these agreements had been triggered on December 31, 2010, OTP would have been required to provide $4,685,000 in additional cash to its counterparties. The remaining derivative liability balance of $6,660,000 relates to mark-to-market losses on contracts that have no ratings triggers or deposit requirements.

6. Common Shares and Earnings Per Share

Common Shares
The Company did not issue or retire any common shares during the three months ended March 31, 2011.

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

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the quarters ended March 31, 2011 and 2010:

Quarter Ended March 31,	Options Outstanding	Range of Exercise Prices
2011	383,460	$24.93 – $31.34
2010	390,210	$24.93 – $31.34

7. Share-Based Payments

The Company has five share-based payment programs. No new stock awards were granted under these programs in the first quarter of 2011. As of March 31, 2011 the remaining unrecognized compensation expense related to stock-based compensation was approximately $2.3 million (before income taxes) which will be amortized over a weighted-average period of 2.2 years.

Amounts of compensation expense recognized under the Company's five stock-based payment programs for the three months ended March 31, 2011 and 2010 are presented in the table below:

	Three months ended March 31,	
(in thousands)	2011	2010
Employee Stock Purchase Plan (15% discount)	$62	$69
Restricted Stock Granted to Directors	192	140
Restricted Stock Granted to Employees	115	118
Restricted Stock Units Granted to Employees	83	60
Stock Performance Awards Granted to Executive Officers	--	222
Totals	$452	$609

9. Commitments and Contingencies

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts
At December 31, 2010 OTP had commitments for capacity and energy requirements under agreements extending through 2032 at annual costs of approximately $20,134,000 in 2011, $21,637,000 in 2012, $16,492,000 in 2013, $15,388,000 in 2014, $12,307,000 in 2015 and $78,879,000 for the years beyond 2015. In the first quarter of 2011, OTP entered into additional energy purchase agreements increasing its commitments for capacity and energy requirements by $1,134,000 in 2011, $3,388,000 in 2012, $5,376,000 in 2013, $9,313,000 in 2014 and $6,608,000 in 2015.

OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. In the first quarter of 2011, OTP extended its contract for the purchase of coal for Hoot Lake Plant resulting in an increase in minimum purchase commitments of $2,145,000 in 2011 and $5,198,000 in 2012. OTP’s current coal purchase agreements now expire in 2012 and 2016. In total, OTP is now committed to the minimum purchase, dating from January 1, 2011, of approximately $123,092,000 or to make payments in lieu thereof, under these contracts. The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

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 March 31, 2011 will not be material.

10. Short-Term and Long-Term Borrowings

The following table presents the status of our lines of credit as of March 31, 2011 and December 31, 2010:

(in thousands)	Line Limit	In Use on March 31, 2011	Restricted due to Outstanding Letters of Credit	Available on March 31, 2011	Available on December 31, 2010
Otter Tail Corporation Credit Agreement	$200,000	$96,976	$1,674	$101,350	$144,350
OTP Credit Agreement	170,000	20,000	1,050	148,950	144,436
Total	$370,000	$116,976	$2,724	$250,300	$288,786

On March 3, 2011 OTP entered into an Amended and Restated Credit Agreement (the OTP Credit Agreement) with the Banks named therein. The OTP Credit Agreement provides for a $170 million line of credit that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. The OTP Credit Agreement is an unsecured revolving credit facility that OTP can draw on to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under the line of credit currently bear interest at LIBOR plus 1.5%, subject to adjustment based on the ratings of OTP’s senior unsecured debt. Under the OTP Credit Agreement OTP is required to pay the Banks’ commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement expires on March 3, 2016.

The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its 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 OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The OTP Credit Agreement amends and restates the $170 million Credit Agreement dated as of July 30, 2008 among OTP (formerly known as Otter Tail Corporation, dba Otter Tail Power Company), the Banks named therein, as amended by a First Amendment to Credit Agreement dated as of April 21, 2009 and a Second Amendment to Credit Agreement dated as of June 22, 2009.

The OTP Credit Agreement also contains certain financial covenants. Specifically, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization (as defined in the OTP Credit Agreement) to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio (as defined in the OTP Credit Agreement) to be less than 1.50 to 1.00.

On March 18, 2011 Otter Tail Corporation borrowed $1.5 million under a Partnership in Assisting Community Expansion loan to finance capital investments made at Northern Pipe Products, Inc., the Company's PVC pipe manufacturing subsidiary located in Fargo, North Dakota. The ten-year unsecured note bears interest at 2.54% with monthly principal and interest payments through March 2021.

The following table provides a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of March 31, 2011:

(in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt – Credit Lines	$20,000		$96,976	$116,976
Long-Term Debt:				
Senior Unsecured Notes 6.63%, due December 1, 2011	$90,000			$90,000
Pollution Control Refunding Revenue Bonds, Variable, 2.50% at March 31, 2011, due December 1, 2012	10,400			10,400
9.000% Notes, due December 15, 2016			$100,000	100,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000			33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,090			5,090
Senior Unsecured Note 8.89%, due November 30, 2017			50,000	50,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000			30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,215			20,215
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Other Obligations - Various up to 13.31% at March 31, 2011		$4,546	1,501	6,047
Total	$280,705	$4,546	$151,501	$436,752
Less:				
Current Maturities	--	589	94	683
Unamortized Debt Discount	--	--	5	5
Total Long-Term Debt				