

OTTER TAIL CORP
Form 10-Q
November 09, 2006

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**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 **September 30, 2006**

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 0-368

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

Minnesota

41-0462685

(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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act (check one):

Large accelerated filer Accelerated filer Non-accelerated filer

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:

October 31, 2006 29,505,159 Common Shares (\$5 par value)

OTTER TAIL CORPORATION
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Consolidated Balance Sheets**

(not audited)

-Assets-

	September 30, 2006	December 31, 2005
	(Thousands of dollars)	
Current assets		
Cash and cash equivalents	\$ 7,999	\$ 5,430
Accounts receivable:		
Trade net	130,421	117,796
Other	9,599	11,790
Inventories	106,601	88,677
Deferred income taxes	6,967	6,871
Accrued utility revenues	20,091	22,892
Costs and estimated earnings in excess of billings	41,733	21,542
Other	14,360	16,476
Assets of discontinued operations	409	13,701
Total current assets	338,180	305,175
Investments and other assets	36,992	33,824
Goodwill net	98,110	98,110
Other intangibles net	20,360	21,160
Deferred debits		
Unamortized debt expense and reacquisition premiums	6,193	6,520
Regulatory assets and other deferred debits	17,259	19,616
Total deferred debits	23,452	26,136
Plant		
Electric plant in service	921,642	910,766
Nonelectric operations	235,893	228,548
Total plant	1,157,535	1,139,314
Less accumulated depreciation and amortization	472,876	459,438
Plant net of accumulated depreciation and amortization	684,659	679,876
Construction work in progress	37,042	17,215
Net plant	721,701	697,091
Total	\$ 1,238,795	\$ 1,181,496

See accompanying notes to consolidated financial statements

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

	September 30, 2006	December 31, 2005
	(Thousands of dollars)	
Current liabilities		
Short-term debt	\$ 54,037	\$ 16,000
Current maturities of long-term debt	3,087	3,340
Accounts payable	115,118	97,239
Accrued salaries and wages	25,684	24,326
Accrued federal and state income taxes	2,108	8,449
Other accrued taxes	10,008	12,518
Other accrued liabilities	16,248	14,124
Liabilities of discontinued operations	187	10,983
Total current liabilities	226,477	186,979
Pensions benefit liability	24,397	23,216
Other postretirement benefits liability	28,033	26,982
Other noncurrent liabilities	17,137	18,683
Deferred credits		
Deferred income taxes	112,351	113,737
Deferred investment tax credit	8,467	9,327
Regulatory liabilities	65,343	61,624
Other	1,430	1,500
Total deferred credits	187,591	186,188
Capitalization		
Long-term debt, net of current maturities	256,223	258,260
Class B stock options of subsidiary	1,258	1,258
Cumulative preferred shares authorized 1,500,000 shares without par value; outstanding 2006 and 2005 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 2006 29,499,053 and 2005 29,401,223	147,495	147,006

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Premium on common shares	98,124	96,768
Unearned compensation		(1,720)
Retained earnings	242,392	228,515
Accumulated other comprehensive loss	(5,832)	(6,139)
Total common equity	482,179	464,430
Total capitalization	755,160	739,448
Total	\$ 1,238,795	\$ 1,181,496

See accompanying notes to consolidated financial statements

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Otter Tail Corporation
Consolidated Statements of Income
(not audited)

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2006	2005	2006	2005
	(In thousands, except share and per share amounts)		(In thousands, except share and per share amounts)	
Operating revenues				
Electric	\$ 71,206	\$ 85,770	\$ 227,308	\$ 233,403
Non-electric	209,336	175,417	590,945	489,667
Total operating revenues	280,542	261,187	818,253	723,070
Operating expenses				
Production fuel - electric	15,846	14,485	42,108	40,211
Purchased power - electric system use	8,590	13,295	44,990	44,737
Electric operation and maintenance expenses	26,433	23,383	77,889	72,635
Cost of goods sold - non-electric (excludes depreciation; included below)	161,148	135,662	449,905	372,894
Other non-electric expenses	29,543	26,428	85,097	74,712
Depreciation and amortization	12,552	11,720	37,155	34,658
Property taxes - electric	2,260	2,735	7,429	7,816
Total operating expenses	256,372	227,708	744,573	647,663
Operating income	24,170	33,479	73,680	75,407
Other income	1,060	1,071	2,147	1,472
Interest charges	5,078	4,633	14,622	14,007
Income from continuing operations before income taxes	20,152	29,917	61,205	62,872
Income taxes - continuing operations	6,676	10,749	21,737	21,676
Net income from continuing operations	13,476	19,168	39,468	41,196
Discontinued operations				
(Loss) income from discontinued operations net of taxes of \$0; (\$391); \$28 and (\$161) for the respective periods		(589)	26	(252)
Goodwill impairment loss		(1,003)		(1,003)
Net gain on disposition of discontinued operations - net of taxes of \$0; \$17; \$224 and \$5,786 for the respective periods		27	336	9,937
Net income from discontinued operations		(1,565)	362	8,682

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Net income	13,476	17,603	39,830	49,878
Preferred dividend requirements	183	185	551	552
Earnings available for common shares	\$ 13,293	\$ 17,418	\$ 39,279	\$ 49,326
Basic earnings per common share:				
Continuing operations (net of preferred dividend requirement)	\$ 0.45	\$ 0.65	\$ 1.33	\$ 1.39
Discontinued operations	\$	\$ (0.05)	\$ 0.01	\$ 0.30
	\$ 0.45	\$ 0.60	\$ 1.34	\$ 1.69
Diluted earnings per common share:				
Continuing operations (net of preferred dividend requirement)	\$ 0.45	\$ 0.64	\$ 1.31	\$ 1.39
Discontinued operations	\$	\$ (0.05)	\$ 0.01	\$ 0.29
	\$ 0.45	\$ 0.59	\$ 1.32	\$ 1.68
Average number of common shares outstanding basic				
	29,412,526	29,245,640	29,377,158	29,176,625
Average number of common shares outstanding diluted				
	29,805,897	29,441,410	29,764,752	29,289,438
Dividends per common share	\$ 0.2875	\$ 0.2800	\$ 0.8625	\$ 0.8400

See accompanying notes to consolidated financial statements

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

	Nine months ended	
	September 30,	
	2006	2005
	(Thousands of dollars)	
Cash flows from operating activities		
Net income	\$ 39,830	\$ 49,878
Adjustments to reconcile net income to net cash provided by operating activities:		
Net gain from sale of discontinued operations	(336)	(9,937)
(Income) loss from discontinued operations	(26)	1,255
Depreciation and amortization	37,155	34,658
Deferred investment tax credit	(860)	(864)
Deferred income taxes	52	(1,854)
Change in deferred debits and other assets	(564)	3,310
Discretionary contribution to pension plan	(4,000)	(4,000)
Change in noncurrent liabilities and deferred credits	4,552	4,466
Allowance for equity (other) funds used during construction	(611)	(601)
Change in derivatives net of regulatory deferral	3,364	(2,927)
Stock compensation expense	1,871	1,885
Other net	(123)	349
Cash (used for) provided by current assets and current liabilities:		
Change in receivables	(9,063)	(7,605)
Change in inventories	(17,663)	(7,682)
Change in other current assets	(19,260)	(9,370)
Change in payables and other current liabilities	12,248	(7,840)
Change in interest and income taxes payable	(3,831)	(3,996)
Net cash provided by continuing operations	42,735	39,125
Net cash provided by discontinued operations	1,011	3,117
Net cash provided by operating activities	43,746	42,242
Cash flows from investing activities		
Capital expenditures	(53,291)	(42,150)
Proceeds from disposal of noncurrent assets	3,623	3,923
Acquisitions net of cash acquired		(11,223)
(Increases) decreases in other investments	(3,540)	3,369
Net cash used in investing activities continuing operations	(53,208)	(46,081)
Net proceeds from the sales of discontinued operations	1,898	33,685
Net cash provided by investing activities discontinued operations		559
Net cash used in investing activities	(51,310)	(11,837)

Cash flows from financing activities

Change in checks written in excess of cash	(11)	1,970
Net short-term borrowings	38,037	(6,950)
Proceeds from issuance of common stock, net of issuance expenses	1,634	8,266
Payments for retirement of common stock	(463)	(365)
Proceeds from issuance of long-term debt	142	339
Debt issuance expenses	(302)	
Payments for retirement of long-term debt	(2,523)	(5,304)
Dividends paid	(25,954)	(25,060)
Net cash provided by (used in) financing activities – continuing operations	10,560	(27,104)
Net cash used in financing activities – discontinued operations		(2,996)
Net cash provided by (used in) financing activities	10,560	(30,100)
Effect of foreign exchange rate fluctuations on cash	(427)	(305)
Net change in cash and cash equivalents	2,569	
Cash and cash equivalents at beginning of period – continuing operations	5,430	
Cash and cash equivalents at end of period – continuing operations	\$ 7,999	\$

Supplemental cash flow information

Cash paid during the year from continuing operations for:		
Interest (net of amount capitalized)	\$ 11,419	\$ 11,321
Income taxes	\$ 28,967	\$ 26,625
Cash paid during the year from discontinued operations for:		
Interest	\$ 91	\$ 118
Income taxes	\$ 423	\$ 2,293

See accompanying notes to consolidated financial statements

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OTTER TAIL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated results of operations for the periods presented. The consolidated financial statements and notes thereto should be read in conjunction with the consolidated financial statements and notes as of and for the years ended December 31, 2005, 2004 and 2003 included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005. Because of seasonal and other factors, the earnings for the three-month and nine-month periods ended September 30, 2006 should not be taken as an indication of earnings for all or any part of the balance of the year.

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 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 the electric utility's forward energy contracts and the energy services company's swap transactions, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with Statement of Financial Accounting Standards (SFAS) No. 133 and Emerging Issues Task Force (EITF) Issues 02-3 and 03-11. Gains and losses on forward energy contracts subject to regulatory treatment are deferred and recognized on a net basis in revenue in the period realized. Idaho Pacific Holdings, Inc. (IPH), enters into forward natural gas contracts to hedge its exposure to fluctuations in natural gas prices related to future purchases of natural gas for its Ririe, Idaho and Center, Colorado dehydration plants. These forward contracts are derivatives subject to mark-to-market accounting that qualify as cash flow hedges, with unrealized gains and losses being recognized as components of other comprehensive income. On settlement, realized gains and losses are recognized as components of fuel expense in cost of goods sold.

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 Company's operating companies enter into fixed-price construction contracts. Revenues under these contracts are primarily recognized on a percentage-of-completion basis. The method used to determine the percentage of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company's wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. The following summarizes costs incurred, billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	September 30, 2006	December 31, 2005
Costs incurred on uncompleted contracts	\$ 224,633	\$ 194,076
Less billings to date	(240,269)	(203,862)
Plus estimated earnings recognized	26,782	22,834
	\$ 11,146	\$ 13,048

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

(in thousands)	September 30, 2006	December 31, 2005
Costs and estimated earnings in excess of billings on uncompleted contracts	\$ 41,733	\$ 21,542
Billings in excess of costs and estimated earnings on uncompleted contracts	(30,587)	(8,494)
	\$ 11,146	\$ 13,048

Adjustments and Reclassifications

The Company's consolidated statements of income for the three and nine months ended September 30, 2005, its consolidated statement of cash flows for the nine months ended September 30, 2005 and its December 31, 2005 consolidated balance sheet reflect the reclassifications of the operating results, assets and liabilities of the natural gas marketing operations of OTESCO, the Company's energy services company, to discontinued operations as a result of the sale of these operations in June 2006. The reclassifications had no impact on the Company's total consolidated net income or cash flows for the three or nine months ended September 30, 2005, or on its total consolidated assets or liabilities as of December 31, 2005.

Inventories

Inventories consist of the following:

(in thousands)	September 30, 2006	December 31, 2005
Finished goods	\$ 45,429	\$ 38,928
Work in process	9,546	7,146
Raw material, fuel and supplies	51,626	42,603
	\$ 106,601	\$ 88,677

Goodwill and Other Intangible Assets

Goodwill did not change in the first nine months of 2006 as the Company did not acquire any businesses or make any adjustments to goodwill during the period.

The following table summarizes the components of the Company's intangible assets at September 30, 2006 and December 31, 2005.

(in thousands)	September 30, 2006			December 31, 2005		
	Gross carrying amount	Accumulated amortization	Net carrying amount	Gross carrying amount	Accumulated amortization	Net carrying amount
Amortized intangible assets:						
Covenants not to compete	\$ 2,198	\$ 1,734	\$ 464	\$ 2,338	\$ 1,620	\$ 718
Customer relationships	10,599	910	9,689	10,575	583	9,992
Other intangible assets including contracts	2,083	1,229	854	2,785	1,680	1,105

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Total	\$ 14,880	\$ 3,873	\$ 11,007	\$ 15,698	\$ 3,883	\$ 11,815
Non-amortized intangible assets:						
Brand/trade name	\$ 9,353	\$	\$ 9,353	\$ 9,345	\$	\$ 9,345

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Intangible assets with finite lives are being amortized over average lives ranging from one to twenty-five years. The amortization expense for these intangible assets was \$831,000 for the nine months ended September 30, 2006 compared to \$855,000 for the nine months ended September 30, 2005. The estimated annual amortization expense for these intangible assets for the next five years is: \$1,078,000 for 2006, \$848,000 for 2007, \$727,000 for 2008, \$636,000 for 2009 and \$507,000 for 2010.

Comprehensive Income

(in thousands)	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Net income	\$ 13,476	\$ 17,603	\$ 39,830	\$ 49,878
Other comprehensive income (net-of-tax)				
Minimum pension liability adjustment				(1,263)
Foreign currency translation (loss) gain	(19)	666	545	407
Unrealized (loss) on cash flow hedges	(271)		(271)	
Unrealized gain (loss) on available-for-sale securities	45	(15)	33	(21)
Total other comprehensive income	(245)	651	307	(877)
Total comprehensive income	\$ 13,231	\$ 18,254	\$ 40,137	\$ 49,001

The foreign currency translation adjustments are associated with the Canadian operations of IPH. The unrealized loss on cash flow hedges is associated with forward natural gas contracts entered into by IPH that are derivatives subject to mark-to-market accounting. The unrealized losses on available-for-sale securities are associated with investments of the Company's captive insurance company.

New Accounting Standards

SFAS No. 123(R) (revised 2004), *Share-Based Payment*, issued in December 2004 is a revision of SFAS No. 123, *Accounting for Stock-based Compensation*, and supersedes Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*. Beginning in January 2006, the Company adopted SFAS No. 123(R) on a modified prospective basis. The Company is required to record stock-based compensation as an expense on its income statement over the period earned based on the fair value of the stock or options awarded on their grant date. The application of SFAS No. 123(R) reporting requirements will result in recording compensation expense of approximately \$160,000, net-of-tax, in 2006 for non-vested stock options that were outstanding on December 31, 2005. Additionally, the application of SFAS No. 123(R) reporting requirements will result in recording compensation expense of approximately \$240,000 in 2006 for the 15% discount offered under the Company's Employee Stock Purchase Plan based on amounts currently being withheld for investment by participants. See additional discussion under *Share-based Payments* in the footnotes that follow. For years prior to 2006, we reported our stock-based compensation under the requirements of APB No. 25 and furnished related pro forma footnote information required under SFAS No. 123.

SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*, an amendment of Financial Accounting Standards Board (FASB) Statements No. 133 and 140, was issued in February 2006. This statement amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to resolve issues addressed in SFAS No. 133 Implementation Issue No. D1, *Application of Statement 133 to Beneficial Interests in Securitized Financial Assets*. This statement also amends SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, to eliminate the prohibition on a qualifying special purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. This Statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. The Company has not issued nor does it currently

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hold any financial instruments that would be affected by this statement and does not anticipate that this statement will have any impact on its consolidated financial statements on the date the statement becomes effective.

FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*, was issued by the FASB in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS 109, *Accounting for Income Taxes*. The Company will be required to recognize in its financial statements the tax effects of a tax position that is more-likely-than-not to be sustained on audit based solely on the technical merits of the position as of the reporting date. The term more-likely-than-not means a likelihood of more than 50%. FIN No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. FIN No. 48 is effective as of the beginning of the first fiscal year after December 15, 2006, which will be as of January 1, 2007, for the Company. Only tax positions that meet the more-likely-than-not threshold at that date may be recognized. The cumulative effect of initially applying FIN No. 48 will be recognized as a change in accounting principle as of the end of the period in which FIN No. 48 is adopted. The Company is currently assessing the impact of FIN No. 48 on its uncertain tax positions.

SFAS No. 157, *Fair Value Measurements*, was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 will be effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. The Company cannot predict what, if any, impact this new standard will have on its consolidated financial statements when the standard becomes effective in 2008.

SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, was issued by the FASB in September 2006. SFAS No. 158 requires employers to recognize, on a prospective basis, the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and to recognize, as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits and transition assets or obligations that have not been recognized as components of net periodic benefit cost. SFAS No. 158 also requires additional disclosures in the notes to financial statements. SFAS No. 158 will not change the amount of net periodic benefit expense recognized in an entity's income statement. It is effective for fiscal years ending after December 15, 2006. The Company is currently assessing the impact of SFAS No. 158 on its consolidated financial statements. Application of this standard at December 31, 2005 would have resulted in an increase in the pension benefit and other postretirement liability of \$44.4 million, a decrease in intangible pension asset of \$6.5 million, a decrease in deferred tax liability of \$20.4 million and a decrease in stockholders' equity of \$30.5 million. The effect at December 31, 2006, the adoption date, could vary significantly. The amounts recorded at December 31, 2006 will depend on a number of assumptions, including the discount rates in effect at December 31, 2006, the actual rate of return on the pension plan assets for 2006 and the tax effects of the adjustment. Changes in these assumptions since our last measurement date could increase or decrease the expected impact of implementing SFAS No. 158 in our consolidated financial statements at December 31, 2006. The Company does not expect adoption of this standard to have an effect on compliance with debt covenants maintained in its financing agreements. The Company is reviewing the regulatory accounting implications of this standard to determine if any amounts indicated for inclusion in other comprehensive income may qualify for regulatory accounting treatment and be classified as regulatory assets under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*.

Securities and Exchange Commission Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*, was issued in September 2006 to address diversity in practice in quantifying financial statement misstatements. SAB No. 108 requires a company to quantify misstatements based on their impact on each of its consolidated financial statements and related disclosures. SAB 108 is effective for the Company as of December 31, 2006, allowing a

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one-time transitional cumulative effect adjustment to retained earnings as of July 1, 2006, for errors that were not previously deemed material, but are material under the guidance in SAB 108. The Company does not expect the adoption of SAB 108 to have a material impact on its consolidated financial statements.

Segment Information

The Company's businesses have been classified into six segments based on products and services and reach customers in all 50 states and international markets. The six segments are: electric, plastics, manufacturing, health services, food ingredient processing and other business operations.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota under the name Otter Tail Power Company. Electric utility operations have been the Company's primary business since incorporation.

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

Manufacturing consists of businesses in the following manufacturing activities: production of waterfront equipment, wind towers, material and handling trays and horticultural containers; contract machining; and metal parts stamping and fabrication. These businesses are located primarily in the Upper Midwest and Missouri.

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 service maintenance, diagnostic imaging, positron emission tomography and nuclear medicine imaging, portable X-ray imaging and rental of diagnostic medical imaging equipment to various medical institutions located throughout the United States.

Food ingredient processing consists of IPH, which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado and Souris, Prince Edward Island, Canada, producing dehydrated potato products that are sold in the United States, Canada, Europe, the Middle East, the Pacific Rim and Central America.

Other business operations consists of businesses involved in residential, commercial and industrial electric contracting industries; fiber optic and electric distribution systems; waste-water, water and HVAC systems construction; transportation; energy services; and the portion of corporate general and administrative expenses that are not allocated to other segments. These businesses operate primarily in the Central United States, except for the transportation company which operates in 48 states and six Canadian provinces.

The Company's electric operations, including wholesale power sales, are operated as a division of Otter Tail Corporation, and the Company's energy services operations are operated as a subsidiary of Otter Tail Corporation. Substantially all of the other businesses are owned by a wholly owned subsidiary of the Company.

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 on continuing operations for the business segments for three and nine month periods ended September 30, 2006 and 2005 and total assets by business segment as of September 30, 2006 and December 31, 2005 are presented in the following tables.

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Operating Revenue

(in thousands)	Three months ended		Nine months ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Electric	\$ 71,206	\$ 85,770	\$ 227,308	\$ 233,403
Plastics	45,941	45,462	136,731	113,621
Manufacturing	76,667	59,803	226,555	183,190
Health services	35,432	30,653	100,341	89,775
Food ingredient processing	11,474	9,808	30,635	27,297
Other business operations	40,739	30,805	99,397	78,781
Intersegment eliminations	(917)	(1,114)	(2,714)	(2,997)
Total	\$ 280,542	\$ 261,187	\$ 818,253	\$ 723,070

Income (Loss) Before Income Taxes

(in thousands)	Three months ended		Nine months ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Electric	\$ 9,982	\$ 24,351	\$ 29,958	\$ 43,906
Plastics	7,645	4,873	23,450	13,230
Manufacturing	4,146	1,459	14,849	10,678
Health services	543	1,898	2,044	5,282
Food ingredient processing	(1,768)	505	(5,156)	2,114
Other business operations*	(396)	(3,169)	(3,940)	(12,338)
Total	\$ 20,152	\$ 29,917	\$ 61,205	\$ 62,872

* Other business operations includes unallocated corporate expenses of \$2,606,000 and \$3,224,000 for the three months ended September 30, 2006 and 2005, respectively, and \$8,645,000 and \$11,078,000 for the nine months ended

September 30,
2006 and 2005,
respectively.

Total Assets

(in thousands)	September 30, 2006	December 31, 2005
Electric	\$ 663,349	\$ 654,175
Plastics	81,502	76,573
Manufacturing	219,118	177,969
Health services	65,636	67,066
Food ingredient processing	96,004	96,023
Other business operations	112,777	95,989
Discontinued operations	409	13,701
Total	\$ 1,238,795	\$ 1,181,496

No single external customer accounts for 10% or more of the Company's revenues. Substantially all of the Company's long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Ft. Erie, Ontario, Canada.

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

(in thousands)	Three months ended		Nine months ended	
	September 30, 2006	September 30, 2005	September 30, 2006	September 30, 2005
United States of America	96.8%	97.8%	97.0%	97.9%
Canada	1.4%	0.8%	1.5%	1.0%
All other countries	1.8%	1.4%	1.5%	1.1%

Rate and Regulatory Matters

On December 29, 2000 the North Dakota Public Service Commission (NDPSC) approved a performance-based ratemaking plan that links allowed earnings in North Dakota to seven defined performance standards in the areas of price, electric service reliability, customer satisfaction and employee safety. The plan was in place through 2005. The electric utility's 2005 rate of return was within the allowable range defined in the plan, so no refunds or recoveries were ordered under the plan for 2005. The electric utility had applied to the NDPSC for a three year extension of the performance-based ratemaking plan with certain modifications. In May 2006, the NDPSC indicated that it did not wish to continue performance-based ratemaking at this time and the electric utility requested that its application be withdrawn.

In September 2004, a letter was provided to the Minnesota Public Utilities Commission (MPUC) summarizing issues and conclusions of an internal investigation completed by the Company related to claims of allegedly improper regulatory filings brought to the attention of the Company by certain individuals. On November 30, 2004 the electric utility filed a report with the MPUC responding to these claims. In 2005, the Energy Division of the Department of Commerce (DOC), the Residential Utilities Division of the Office of Attorney General and the claimants filed comments in response to the report, to which the Company filed reply comments. A hearing before the MPUC was held on February 28, 2006. As a result of the hearing, the electric utility agreed that within 90 days it would file a revised Regulatory Compliance Plan, an updated Corporate Cost Allocation Manual and documentation of the definitions of its chart of accounts. The electric utility filed these documents with the MPUC in the second quarter of 2006. The Company has received comments on its filings from the DOC and the claimants and filed reply comments in August 2006. The DOC has recommended accepting the revised Regulatory Compliance Plan and the chart of accounts definition. The Company continues to work with the MPUC staff and the DOC on the Corporate Allocation Manual and expects to file supplemental comments in November 2006. The electric utility also agreed to file a general rate case in Minnesota on or before September 30, 2007.

In a letter from the Federal Energy Regulatory Commission (FERC) Office of Market Oversight and Investigations (OMOI) dated September 27, 2005 the electric utility was informed that the Division of Operation Audits of the OMOI would be commencing an audit of the electric utility. The purpose of the audit is to determine whether and how the electric utility's transmission practices are in compliance with the FERC's applicable rules and regulations and tariff requirements and whether and how the implementation of the electric utility's waivers from the requirements of Order No. 889 and Order No. 2004 restricts access to transmission information that would benefit the electric utility's off-system sales. As of the date of this report on Form 10-Q, the Division of Operation Audits of the OMOI had completed its audit work but had not issued an audit report. The Company cannot predict if the results of the audit will have any impact on the Company's consolidated financial statements.

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In December 2005 the MPUC issued an order denying the electric utility's request to allow recovery of certain Midwest Independent Transmission System Operator (MISO)-related costs through the fuel clause adjustment (FCA) in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. A \$1.9 million reduction in revenue and a refund payable was recorded in December 2005 by the electric utility to reflect the refund obligation. On February 9, 2006 the MPUC decided to reconsider its December 2005 order. The Commission's final order was issued on February 24, 2006. In the final order the MPUC ordered jurisdictional investor-owned utilities in the state to participate with the Minnesota Department of Commerce and other parties in a proceeding that will evaluate suitability of recovery of certain MISO Day 2 energy market costs through the FCA. The Minnesota utilities and other parties submitted a final report to the MPUC in July 2006. As of the date of this report on Form 10-Q, the MPUC had not reached a decision on the future treatment of certain MISO-related costs within the FCA or responded to the report submitted by the Minnesota utilities and other parties. In addition, the February 24, 2006 order eliminated the refund provision from the December 2005 order, and allowed that any MISO-related costs not recovered through the FCA may be deferred for a period of 36 months, with possible recovery through base rates in the electric utility's next general rate case which, for Otter Tail Power Company, is expected to be filed on or before September 30, 2007. As a result of this order, the electric utility recognized \$1.9 million in revenue and reversed the refund payable in February 2006 and expects to recover all MISO-related costs through the FCA or to seek recovery, in a rate case, of any MISO-related costs not recoverable through the FCA. On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time revenue sufficiency guarantee (RSG) charges that were not allocated to day-ahead virtual supply offers in accordance with MISO's Transmission and Energy Markets Tariff (TEMT) going back to the commencement of MISO Day 2 markets in April 2005. On May 17, 2006, the FERC issued a Notice of Extension of Time permitting the MISO to delay compliance with the directives contained in its April 2006 order, including the requirement to refund to customers the amounts due, with interest, from April 1, 2005 and the requirement to submit a compliance filing. The Notice stated that the order on rehearing would provide the appropriate guidance regarding the timing of compliance filing. On October 26, 2006, the FERC issued an order on rehearing stating it would not require refunds related to real-time RSG charges that had not been allocated to day-ahead virtual supply offers in accordance with MISO's TEMT going back to the commencement of the MISO Day 2 market in April 2005. However, the FERC ordered prospective allocation of RSG charges to virtual transactions consistent with the TEMT to prevent future inequity and directed MISO to propose a charge that assesses RSG costs to virtual supply offers based on the RSG costs they cause within 60 days of the October 26, 2006 order.

Table of Contents**Regulatory Assets and Liabilities**

As a regulated entity the Company and the electric utility account for the financial effects of regulation in accordance with SFAS No. 71, *Accounting for the Effect of Certain Types of Regulation*. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation.

The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheet:

(in thousands)	September 30, 2006	December 31, 2005
Regulatory assets:		
Deferred income taxes	\$ 14,718	\$ 16,724
Accrued cost-of-energy revenue	11,529	10,400
Reacquisition premiums	2,768	2,995
Deferred marked-to-market losses	1,722	1,423
Deferred conservation program costs	546	1,064
Accumulated ARO accretion/depreciation adjustment	279	209
Plant acquisition costs	163	196
Total regulatory assets	\$ 31,725	\$ 33,011
Regulatory liabilities:		
Accumulated reserve for estimated removal costs	\$ 58,056	\$ 52,582
Deferred income taxes	5,412	5,961
Deferred marked-to-market gains	1,723	2,925
Gain on sale of division office building	152	156
Total regulatory liabilities	\$ 65,343	\$ 61,624
Net regulatory liability position	\$ 33,618	\$ 28,613

The regulatory assets and liabilities related to deferred income taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes*. Reacquisition premiums included in *Unamortized debt expense and reacquisition premiums* are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 15.8 years. Deferred conservation program costs represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. Plant acquisition costs will be amortized over the next 3.7 years. Accrued cost-of-energy revenue included in *Accrued utility revenues* will be recovered over the next 10 months. All deferred marked-to-market gains and losses are related to forward purchases and sales of energy scheduled for delivery prior to March 2007. The accumulated reserve for estimated removal costs is reduced for actual removal costs incurred. The remaining regulatory assets and liabilities are being recovered from, or will be paid to, electric customers over the next 30 years.

If for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an extraordinary expense or income item in the period in which the application of SFAS No. 71 ceases.

Table of Contents**Share-based Payments**

On January 1, 2006 the Company adopted the accounting provisions of SFAS No. 123(R) (revised 2004), *Share-Based Payment*, on a modified prospective basis. SFAS No. 123(R) is a revision of SFAS No. 123, *Accounting for Stock-based Compensation*, and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*.

Under SFAS No. 123(R), the Company records stock-based compensation as an expense on its income statement over the period earned based on the estimated fair value of the stock or options awarded on their grant date. The Company elected the modified prospective method of adopting SFAS No. 123(R), under which prior periods are not retroactively revised. The valuation provisions of SFAS No. 123(R) apply to awards granted after the effective date.

Estimated stock-based compensation expense for awards granted prior to the effective date but that remain nonvested on the effective date will be recognized over the remaining service period using the compensation cost estimated for the SFAS No. 123 pro forma disclosures. Additionally, the adoption of SFAS No. 123(R) resulted in the reclassification of \$798,000 in credits related to outstanding restricted share-based compensation from equity on the Company's consolidated balance sheet to a liability on January 1, 2006 because of income tax withholding provisions in the share-based award agreements. The adoption of SFAS 123(R) also resulted in the elimination of *Unearned compensation* from the equity section of the Company's consolidated balance sheet on January 1, 2006 by netting the account balance of \$1,720,000 against *Premium on common shares*.

On April 10, 2006, the Company's shareholders approved amendments to the 1999 Stock Incentive Plan, as Amended (Incentive Plan) increasing the number of common shares available under the Incentive Plan from 2,600,000 common shares to 3,600,000 common shares, extending the term of the Incentive Plan from December 13, 2008 to December 13, 2013 and making certain other changes to the terms of the Incentive Plan.

As of September 30, 2006, the total remaining unrecognized amount of compensation expense related to stock-based compensation was approximately \$4.0 million (before income taxes), which will be amortized over a weighted-average period of 2.1 years.

The Company has six share-based payment programs. The effect of SFAS No. 123(R) accounting on each of these programs is explained in the following paragraphs.

1999 Employee Stock Purchase Plan, as Amended (Purchase Plan)

On April 10, 2006, the Company's shareholders approved an amendment to the Purchase Plan increasing the number of common shares available under the Purchase Plan from 400,000 common shares to 900,000 common shares.

The Purchase Plan allows employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six month investment period. Under SFAS 123(R) the Company is required to record compensation expense related to the 15% discount which was not required under APB No. 25. Based on the participants' current level of withholdings, the Company estimates that the 15% discount will amount to approximately \$240,000 in 2006. The Company recorded \$174,000 in compensation expense for the nine month period ended September 30, 2006 related to the Purchase Plan. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company. The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive for the purpose of calculating diluted earnings per share during the investment period. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. The purchase of 27,543 common shares in the open market to satisfy the requirements of the Purchase Plan for the six month investment period ended June 30, 2006, was completed on August 1, 2006.

Stock Options Granted Under the Incentive Plan

Since the inception of the Incentive Plan in 1999, the Company has granted 2,041,500 options for the purchase of the Company's common stock. Of the options granted, 1,999,412 had vested or were forfeited and 42,088 were not

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vested as of September 30, 2006. The exercise price of the options granted has been the average market price of the Company's common stock on the grant date. These options were not compensatory under APB No. 25 accounting rules. Under SFAS No.123(R) accounting, compensation expense will be recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under SFAS No. 123(R) accounting, the fair value of the options granted will be recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the Incentive Plan has been based on the Black-Scholes option pricing model.

Under the modified prospective application of SFAS No.123(R) accounting requirements, the difference between the intrinsic value of nonvested options and the fair value of those options of \$362,000 (\$217,000 net-of-tax) on January 1, 2006 is being recognized on a straight-line basis as compensation expense over the remaining vesting period of the nonvested options, which, for nonvested options outstanding on January 1, 2006, will be from January 1, 2006 through April 30, 2007. Accordingly, the Company recorded compensation expense related to nonvested options issued under the Incentive Plan for the three and nine month periods ended September 30, 2006 of \$68,000 (\$41,000 net-of-tax) and \$204,000 (\$122,000 net-of-tax), respectively.

Had compensation expense for stock options been determined based on estimated fair value at the award date, as prescribed by SFAS No. 123, the Company's net income for the three and nine month periods ended September 30, 2005 would have decreased as presented in the table below.

(in thousands)	Three months ended September 30, 2005	Nine months ended September 30, 2005
Net income		
As reported	\$ 17,603	\$ 49,878
Total stock-based employee compensation expense determined under fair value based method for all stock option awards net of related tax effects	(213)	(497)
Pro forma	\$ 17,390	\$ 49,381
Basic earnings per share:		
As reported	\$0.60	\$1.69
Pro forma	\$0.59	\$1.67
Diluted earnings per share:		
As reported	\$0.59	\$1.68
Pro forma	\$0.58	\$1.67

For the purpose of calculating diluted earnings per share, the underlying shares of all vested and nonvested in-the-money options (options where the reporting date average market price of underlying shares exceeds the exercise price of the options) are considered dilutive.

Presented below is a summary of the stock options activity for the nine months ended September 30, 2006:

	Options	Weighted average Exercise price	Aggregate intrinsic value (000 s)
Outstanding, January 1, 2006	1,237,164	\$25.58	

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Granted			
Exercised	85,523	\$22.85	\$ 614
Forfeited	28,468	\$28.90	\$ 52
Outstanding, September 30, 2006	1,123,173	\$25.71	\$4,652
Exercisable, September 30, 2006	1,081,085	\$25.65	\$4,556

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The aggregate intrinsic value in the preceding table represents the total intrinsic value (before income taxes), based on the average market price of the Company's common stock on September 30, 2006, which would have been received by the option holders had all option holders exercised their options on that date.

The Company received cash of \$1,948,000 for options exercised in the first nine months of 2006.

The following table summarizes information about options outstanding as of September 30, 2006:

Range of exercise prices	Outstanding as of 9/30/06	Options outstanding		Options exercisable	
		Weighted-average remaining contractual life (yrs)	Weighted-average exercise price	Exercisable as of 9/30/06	Weighted-average exercise price
\$18.80-\$21.94	261,871	3.0	\$ 19.49	261,871	\$ 19.49
\$21.95-\$25.07	61,350	8.5	\$ 24.93	61,350	\$ 24.93
\$25.08-\$28.21	580,952	5.3	\$ 26.52	538,864	\$ 26.47
\$28.22-\$31.34	219,000	5.5	\$ 31.19	219,000	\$ 31.19

Restricted Stock Granted to Directors

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to members of the Company's Board of Directors as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the four-year vesting period of the restricted shares based on the market value of the Company's common stock on the grant date. Under the modified prospective application of SFAS No.123(R) accounting requirements, compensation expense related to nonvested restricted shares outstanding will be recorded based on the estimated fair value of the restricted shares on their grant dates. On April 9, 2006 the Compensation Committee of the Company's Board of Directors granted 19,800 shares of restricted stock to the directors under the Incentive Plan. The restricted shares vest ratably over a four-year vesting period. The amount of compensation expense recorded related to nonvested restricted shares granted to directors under SFAS No. 123(R) for the three and nine month periods ended September 30, 2006 was \$80,000 (\$48,000 net-of-tax) and \$321,000 (\$193,000 net-of-tax), respectively. The amount of compensation expense recorded related to nonvested restricted shares granted to directors based on the intrinsic value of the restricted stock grants under APB No. 25 for the three and nine month periods ended September 30, 2005 was \$71,000 (\$43,000 net-of-tax) and \$190,000 (\$114,000 net-of-tax), respectively. Nonvested restricted shares granted to directors 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.

Presented below is a summary of the status of directors' restricted stock awards for the nine months ended September 30, 2006:

	Shares		Weighted average grant-date fair value
Nonvested, January 1, 2006	27,000	\$	24.59
Granted	19,800	\$	28.24
Vested (fair value: \$376,000)	14,025	\$	26.82
Forfeited			
Nonvested, September 30, 2006	32,775	\$	27.27

Table of Contents**Restricted Stock Granted to Employees**

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the vesting periods of the restricted shares based on the market value of the Company's common stock on the grant date. Because of income tax withholding provisions in the restricted stock award agreements related to restricted stock granted to employees, the value of these grants is considered variable, which, under SFAS No. 123(R), will require the offsetting credit to compensation expense to be recorded as a liability. Under the modified prospective application of SFAS No. 123(R) accounting requirements and accounting rules for variable awards, compensation expense related to nonvested restricted shares granted to employees will be recorded based on the estimated fair value of the restricted shares on their grant dates and adjusted for the estimated fair value of any nonvested restricted shares on each subsequent reporting date. The reporting date fair value of nonvested restricted shares under this program will be based on the average market value of the Company's common stock on the reporting date.

The amount of compensation expense recorded related to nonvested restricted shares granted to employees based on the estimated fair value of the restricted stock grants under SFAS No. 123(R) for the three and nine month periods ended September 30, 2006 was \$183,000 (\$110,000 net-of-tax) and \$625,000 (\$375,000 net-of-tax), respectively. The amount of compensation expense recorded related to nonvested restricted shares granted to employees based on the intrinsic value of the restricted stock grants under APB No. 25 for the three and nine month periods ended September 30, 2005 was \$281,000 (\$169,000 net-of-tax) and \$830,000 (\$498,000 net-of-tax), respectively. The equity account, *Unearned compensation*, was credited when compensation expense was recorded related to these shares under APB No. 25 accounting. Under SFAS 123(R) accounting, a current liability account is credited when compensation expense is recorded. Accumulated liabilities related to nonvested restricted shares issued to employees under this program will be reversed and credited to the *Premium on common shares* equity account as the shares vest. Nonvested restricted shares granted to 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.

Presented below is a summary of the status of employee's restricted stock awards for the nine months ended September 30, 2006:

	Shares		Weighted average reporting-date fair value
Nonvested, January 1, 2006	72,974	\$	28.91
Granted			
Vested (fair value: \$1,167,000)	41,308	\$	28.25
Forfeited			
Nonvested, September 30, 2006	31,666	\$	29.52

Restricted Stock Units Granted to Employees

On April 9, 2006, the Compensation Committee of the Company's Board of Directors granted 47,425 restricted stock units at a weighted average grant-date fair value of \$25.41 per unit to key employees under the Incentive Plan payable in common shares. Each unit is automatically converted into one share of common stock on vesting. Vesting occurs from April 10, 2006 through April 8, 2010, with a weighted average contractual term of stock units outstanding as of September 30, 2006 of 2.8 years.

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Presented below is a summary of the status of employee s restricted stock unit awards for the nine months ended September 30, 2006:

	Restricted stock units	Aggregate grant-date fair value (000 s)
Outstanding, January 1, 2006		\$
Granted	47,425	1,205
Converted	7,450	220
Forfeited	1,105	27
Outstanding, September 30, 2006	38,870	\$ 958

The amount of compensation expense recorded related to both vested and nonvested restricted stock units granted to employees in April 2006 based on the estimated fair value of the restricted stock unit grants under SFAS No. 123(R) using a Monte Carlo valuation method for the three and nine month periods ended September 30, 2006 was \$69,000 (\$41,000 net-of-tax) and \$358,000 (\$215,000 net-of-tax), respectively. The underlying shares related to nonvested restricted stock units granted to employees are considered dilutive for the purpose of calculating diluted earnings per share.

Stock Performance Awards granted to Executive Officers

The Compensation Committee of the Company s Board of Directors has approved stock performance award agreements under the Incentive Plan for the Company s executive officers. Under these agreements, the officers could be awarded shares of the Company s common stock based on the Company s total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period. Under APB No. 25 accounting, these awards were valued based on the average market price of the underlying shares of the Company s common stock on the award grant date, multiplied by the estimated probable number of shares to be awarded at the end of the performance measurement period with compensation expenses recorded ratably over the related three-year measurement period. Compensation expense recognized was adjusted at each reporting date subsequent to the grant date of the awards for the difference between the market value of the underlying shares on their grant date and the market value of the underlying shares on the reporting date. Under the modified prospective application of SFAS No.123(R) accounting requirements, the amount of compensation expense that will be recorded subsequent to January 1, 2006 related to awards granted in 2004 and 2005 and outstanding on September 30, 2006 is based on the estimated grant-date fair value of the awards as determined under the Black-Scholes option pricing model.

On April 9, 2006 the Compensation Committee of the Company s Board of Directors granted stock performance awards to the Company s executive officers under the Incentive Plan. Under these awards, the Company s executive officers could earn up to an aggregate of 88,050 common shares based on the Company s total shareholder return relative to the total shareholder return of the companies that comprise the EEI Index over the performance period of January 1, 2006 through December 31, 2008. The aggregate target share award is 58,700 shares. Actual payment may range from zero to 150 percent of the target amount. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance period. The amount of compensation expense that will be recorded related to awards granted in April 2006 and outstanding on September 30, 2006 is based on the estimated grant-date fair value of the awards as determined under a Monte Carlo valuation method.

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The table below provides a summary of amounts expensed for the stock performance awards for the three and nine month periods ended September 30, 2006 and 2005:

Performance period	Maximum shares subject to award	Shares used to estimate expense	Amount of expense during the three months ended September 30,		Amount of expense during the nine months ended September 30,	
			2006	2005	2006	2005
2004-2006	70,500	23,500	\$ 47,000	\$ 101,000	\$ 140,000	\$ 423,000
2005-2007	75,150	50,872	94,000	223,000	281,000	393,000
2006-2008	88,050	58,700	127,000		381,000	
Total	233,700	133,072	\$268,000	\$324,000	\$802,000	\$816,000

The offsetting credit to amounts expensed related to the stock performance awards is included in common shareholders' equity. For the purpose of calculating diluted earnings per share, shares expected to be awarded are considered dilutive. Currently, the Company intends to purchase shares on the open market for stock performance awards earned.

Class B Stock Options and Class B Stock of Subsidiary

In 2006, IPH granted 305 options to purchase IPH Class B Common Stock to five employees at an exercise price of \$2,085.88 per option. The options vested immediately on issuance. On the date the options were granted the value of a share of IPH Class B common stock was estimated to be \$1,041.71. Therefore, the grant-date fair value of the options was \$0 and no expense or liability was recorded related to these options under SFAS No. 123(R). Prior to the 2006 grant there were options for 755 shares of IPH Class B Common Stock outstanding. As of September 30, 2006, there were 1,060 options outstanding with a combined exercise price of \$952,000, of which 755 options were in-the-money with a combined exercise price of \$316,000.

Common Shares and Earnings per Share

In the first nine months of 2006 the Company issued 85,223 common shares for stock options exercised, 1,727 common shares and 19,800 restricted common shares for director's compensation and 7,450 common shares for restricted stock units that vested on issuance in April 2006. The Company retired 16,370 common shares for tax withholding purposes related to 39,825 restricted shares that vested in the first nine months of 2006.

Basic earnings per common share are calculated by dividing earnings available for common shares by the average number of common shares outstanding during the period excluding any nonvested restricted shares outstanding during the period. Diluted earnings per common share are calculated by adjusting outstanding shares, assuming conversion of all potentially dilutive stock options and vesting of all nonvested restricted shares and restricted stock units outstanding and including contingently issuable shares related to outstanding stock performance awards.

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the three and nine month periods ended September 30, 2006 and September 30, 2005.

	Options Outstanding	Range of Exercises Prices
Three Months Ended September 30, 2006	213,000	\$29.74 - \$31.34
Three Months Ended September 30, 2005	234,374	\$29.74 - \$31.34
Nine Months Ended September 30, 2006	213,000	\$29.74 - \$31.34
Nine Months Ended September 30, 2005	409,749	\$27.245 - \$31.34

Table of Contents**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:

(in thousands)	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Service cost benefit earned during the period	\$ 1,373	\$ 1,313	\$ 3,793	\$ 3,381
Interest cost on projected benefit obligation	2,738	2,413	7,826	7,309
Expected return on assets	(3,086)	(3,040)	(9,216)	(9,032)
Amortization of prior-service cost	185	805	557	1,286
Amortization of net actuarial loss	627		1,383	
Net periodic pension cost	\$ 1,837	\$ 1,491	\$ 4,343	\$ 2,944

The Company made discretionary cash contributions to its pension plan of \$4.0 million during each of the nine months ended September 30, 2006 and 2005.

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:

(in thousands)	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Service cost benefit earned during the period	\$ 107	\$ 111	\$ 320	\$ 295
Interest cost on projected benefit obligation	325	318	977	950
Amortization of prior-service cost	18	17	53	53
Recognized net actuarial loss	118	145	354	353
Net periodic pension cost	\$ 568	\$ 591	\$ 1,704	\$ 1,651

Postretirement Benefits Components of net periodic postretirement benefit cost for health insurance and life insurance benefits for retired electric utility and corporate employees are as follows:

(in thousands)	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Service cost benefit earned during the period	\$ 321	\$ 342	\$ 989	\$ 964
Interest cost on projected benefit obligation	643	574	1,917	1,906
Amortization of transition obligation	187	187	561	561
Amortization of prior-service cost	(77)	(76)	(229)	(230)
Amortization of net actuarial loss	151	215	417	527
Effect of Medicare Part D expected subsidy	(571)	(424)	(1,157)	(826)
Net periodic postretirement benefit cost	\$ 654	\$ 818	\$ 2,498	\$ 2,902

Table of Contents**Discontinued Operations**

In June 2006, OTESCO, the Company's energy services company, sold its gas marketing operations for \$0.5 million in cash. In 2005, the Company completed the sales of Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Net income from OTESCO's gas marketing operations classified under discontinued operations includes an after-tax gain on disposition of \$0.3 million for the nine months ended September 30, 2006. Net income from MIS, SGS and CLC classified under discontinued operations includes an after-tax gain on the sale of MIS of \$11.9 million, an after-tax loss on the sale of SGS of \$1.8 million and an after-tax loss on the sale of CLC of \$0.2 million for the nine months ended September 30, 2005. Discontinued operations includes a \$1.0 million goodwill impairment loss for the three and nine month periods ended September 30, 2005, related to OTESCO's gas marketing operations. SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* requires that OTESCO's gas marketing operations, MIS, SGS and CLC be classified and reported separately as discontinued operations.

The results of discontinued operations for the nine months ended September 30, 2006 and the three and nine months ended September 30, 2005 are summarized as follows:

(in thousands)	Three months ended September 30, 2005			Total
	OTESCO GAS	SGS	CLC	
Operating revenues	\$11,471	\$ 213	\$1,868	\$13,552
(Loss) before income taxes	(1,145)	(161)	(677)	(1,983)
Gain on disposition pretax		44		44
Income tax (benefit)	(57)	(47)	(270)	(374)

(in thousands)	Nine months ended September 30, 2006		Nine months ended September 30, 2005			Total
	OTESCO GAS	OTESCO GAS	MIS	SGS	CLC	
Operating revenues	\$ 28,234	\$38,099	\$ 3,773	\$ 6,542	\$5,640	\$54,054
Income (loss) before income taxes	54	(1,163)	2,167	(1,724)	(696)	(1,416)
Gain (loss) on disposition pretax	560		19,025	(3,002)	(300)	15,723
Income tax expense (benefit)	252	(64)	7,975	(1,890)	(396)	5,625

At September 30, 2006 and December 31, 2005 the major components of assets and liabilities of the discontinued operations were as follows:

(in thousands)	September 30, 2006		December 31, 2005		
	SGS	OTESCO Gas	SGS	CLC	Total
Current assets	\$ 409	\$ 11,384	\$ 857	\$ 1,455	\$ 13,696
Investments and other assets				5	5

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Assets of discontinued operations	\$	409	\$ 11,384	\$ 857	\$ 1,460	\$ 13,701
Current liabilities	\$	187	\$ 10,611	\$ 328	\$ 44	\$ 10,983
Liabilities of discontinued operations	\$	187	\$ 10,611	\$ 328	\$ 44	\$ 10,983

The remaining assets and liabilities of SGS consist of accounts receivable, deferred income tax assets and accounts payable that were not settled or disposed of as of September 30, 2006.

Table of ContentsItem 2. Management's Discussion and Analysis of Financial Condition and Results of Operations**RESULTS OF OPERATIONS****Comparison of the Three Months Ended September 30, 2006 and 2005**

Consolidated operating revenues were \$280.5 million for the three months ended September 30, 2006 compared with \$261.2 million for the three months ended September 30, 2005. Operating income was \$24.2 million for the three months ended September 30, 2006 compared with \$33.5 million for the three months ended September 30, 2005. The Company recorded diluted earnings per share from continuing operations of \$0.45 for the three months ended September 30, 2006 compared to \$0.64 for the three months ended September 30, 2005 and total diluted earnings per share from continuing and discontinued operations of \$0.45 for the three months ended September 30, 2006 compared to \$0.59 for the three months ended September 30, 2005, which included \$(0.05) per share from discontinued operations.

Following is a more detailed analysis of our operating results by business segment for the three and nine month periods ended September 30, 2006 and 2005, followed by our outlook for the remainder of 2006 and a discussion of changes in our consolidated financial position during the nine months ended September 30, 2006.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the three month periods ended September 30, 2006 and 2005 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

(in thousands)	Three months ended September 30,	
	2006	2005
Operating revenues	\$917	\$1,114
Cost of goods sold	359	710
Other nonelectric expenses	558	404

Electric

(in thousands)	Three months ended September 30,		Change	%
	2006	2005		Change
Retail sales revenues	\$ 59,694	\$ 61,481	\$ (1,787)	(2.9)
Wholesale revenues	6,099	17,467	(11,368)	(65.1)
Net marked-to-market gain	(207)	2,406	(2,613)	(108.6)
Other revenues	5,620	4,416	1,204	(27.3)
Total operating revenues	\$ 71,206	\$ 85,770	\$ (14,564)	(17.0)
Production fuel	15,846	14,485	1,361	9.4
Purchased power system use	8,590	13,295	(4,705)	(35.4)
Other operation and maintenance expenses	26,433	23,383	3,050	13.0
Depreciation and amortization	6,430	6,084	346	5.7
Property taxes	2,260	2,735	(475)	(17.4)
Operating income	\$ 11,647	\$ 25,788	\$ (14,141)	(54.8)

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A 2.2% increase in retail megawatt-hour (mwh) sales was more than offset by a decrease in fuel clause adjustment (FCA) revenues resulting in the \$1.8 million decrease in retail revenues for the three months ended September 30, 2006 compared with the three months ended September 30, 2005. The decrease in FCA revenues is due to a decrease in purchased power costs between the quarters. The 2.2% increase in total retail mwh sales is mainly due to a 14.8% increase in industrial mwh sales. However, the price per mwh sold to industrial customers decreased 16.4% resulting in a decrease in revenues from industrial customers of \$0.1 million between the quarters. The increase in mwh sales to industrial customers between the quarters is mainly due to increased consumption by pipeline customers as higher oil prices have led to an increase in the volume of product being transported from Canada and the Williston basin. The decrease in the price per mwh sold to industrial customers is a function of the effect on rates of a decrease in market prices for purchased power between the quarters. A 23.0% increase in cooling degree days contributed to a 2.5% increase in mwh sales to residential customers between the periods.

Wholesale sales revenue from company-owned generation decreased \$1.0 million in the three months ended September 30, 2006 compared to the three months ended September 30, 2005 as a result of a 6.6% decrease in mwhs sold combined with a 7.7% decrease in the price per mwh sold between the periods. While overall mwh generation increased at the Company's plants between the quarters, more generation was dedicated to serve native load customers making less available for wholesale sales. Net losses from energy trading activities including net mark-to-market losses on forward energy contracts were \$0.2 million for the quarter ended September 30, 2006 compared with net revenues of \$12.8 million for the quarter ended September 30, 2005. The \$13.0 million decrease in net revenue from energy trading activities reflects an \$8.5 million reduction in net profits from virtual transactions, a \$2.6 million reduction in net mark-to-market results on forward energy contracts (from a net gain of \$2.4 million in the third quarter of 2005 to a net loss of \$0.2 million in the third quarter of 2006) and a \$1.9 million reduction in profits from purchased power resold. Profits from virtual transactions were \$8.2 million in the third quarter of 2005 compared with losses of \$0.3 million in the third quarter of 2006 as the Midwest Independent Transmission System Operator (MISO) market has matured and become more efficient and as a result of a reduction in virtual transactions due to uncertainties related to the status of Revenue Sufficiency Guarantee (RSG) charges in MISO's Transmission and Energy Markets Tariff.

The increase in other electric operating revenues for the three months ended September 30, 2006 compared to the three months ended September 30, 2005 is mainly due to an increase in revenue from contracted services performed for other area utilities including transmission line permitting and construction work.

The increase in fuel costs for the three months ended September 30, 2006 compared with the three months ended September 30, 2005 is mainly due to a 7.3% increase in mwhs generated at the Company's steam and combustion turbine plants. Generation used for retail electric sales increased 9.8% while generation for wholesale electric sales decreased 6.6% between the periods. The cost of fuel per mwh generated at the Company's steam and combustion turbine plants increased 1.9% between the periods as a result of increases in fuel costs to operate the Company's combustion turbine peaking plants.

The decrease in purchased power system use (to serve retail customers) is due to a 68.1% decrease in mwhs purchased for system use, partially offset by a 102% increase in the cost per mwh of purchased power for system use. An increase in mwhs generated for system use from company-owned plants reduced the need for purchased power to meet system demand in the third quarter of 2006 compared with the third quarter of 2005. The lower level of mwhs purchased for system use came mostly from firm energy purchases with prices indexed to natural gas prices resulting in the 102% increase in the price per mwh purchased for system use.

The increase in other operation and maintenance expenses for the three months ended September 30, 2006 compared with the three months ended September 30, 2005 resulted primarily from \$0.8 million in increased costs related to contract work performed for other area utilities, \$0.5 million in increased operating and maintenance costs at the electric utility's generation plants and \$1.1 million from wage and salary increases, higher tree-trimming costs and a decrease in warehousing expenses allocated to material costs.

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Depreciation expense increased in the three months ended September 30, 2006 compared with the three months ended September 30, 2005 as a result of a \$20.6 million increase in electric plant in service in 2005.

The \$0.5 million decrease in property taxes reflects lower property valuations used for determining 2006 property taxes in Minnesota and South Dakota.

Plastics

(in thousands)	Three months ended		Change	% Change
	2006	September 30, 2005		
Operating revenues	\$ 45,941	\$ 45,462	\$ 479	1.1
Cost of goods sold	34,172	37,684	(3,512)	(9.3)
Operating expenses	3,284	1,974	1,310	66.4
Depreciation and amortization	693	629	64	10.2
Operating income	\$ 7,792	\$ 5,175	\$ 2,617	50.6

The increase in operating revenues for the plastics segment between the periods reflects a 23.1% increase in the price per pound of polyvinyl chloride (PVC) and polyethylene (PE) pipe sold, offset by an 18.0% decrease in pounds of pipe sold. The increase in prices reflects the effect of a 14.8% increase in resin costs per pound of PVC pipe shipped between the periods. The decrease in cost of goods sold is a result of the decrease in pounds of pipe sold partially offset by the increase in resin costs per pound of pipe sold. The increase in plastics segment operating expenses between the quarters reflects increased sales, general and administrative expenses directly related to the increases in revenue and operating income. The increase in depreciation and amortization expense is related to capital additions from October 2005 through September 2006, mainly for production equipment.

Manufacturing

(in thousands)	Three months ended		Change	% Change
	2006	September 30, 2005		
Operating revenues	\$ 76,667	\$ 59,803	\$ 16,864	28.2
Cost of goods sold	61,315	49,074	12,241	24.9
Operating expenses	6,563	5,493	1,070	19.5
Depreciation and amortization	2,845	2,497	348	13.9
Operating income	\$ 5,944	\$ 2,739	\$ 3,205	117.0

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

Revenues at DMI Industries, Inc. (DMI) increased \$16.6 million, of which \$8.6 million is related to the new Ft. Erie plant, as a result of increases in production and sales activity.

Revenues at ShoreMaster increased \$1.4 million between the quarters mainly as a result of price increases driven by higher material costs, especially aluminum.

Revenues at T.O. Plastics decreased \$0.1 million as a result of a slight decrease in unit sales between the quarters.

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Revenues at BTD Manufacturing, Inc. (BTD) decreased \$1.0 million mainly as a result of a 7.8% decrease in units sold between the quarters.

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

DMI's cost of goods sold increased \$12.9 million between the quarters, including \$10.0 million in material cost increases. The increase in cost of goods sold is directly related to the increase in DMI's production and sales activity.

Cost of goods sold at ShoreMaster increased \$1.1 million between the quarters as a result of increases in aluminum, subcontractor, labor and benefit costs.

Cost of goods sold at T.O. Plastics decreased \$0.1 million as a result of a decrease in material costs related to a slight decrease in unit sales between the quarters.

Cost of goods sold at BTD decreased \$1.7 million between the quarters mainly due to a decrease in material costs related to the decrease in unit sales between the quarters.

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

Operating expenses at DMI increased \$0.6 million as a result of increases in labor, advertising and professional service expenses mainly related to operations at the new Ft. Erie plant.

ShoreMaster's operating expenses increased \$0.3 million as a result of an increase in bad debt expense between the quarters.

T.O. Plastics operating expenses increased \$0.1 million mostly in sales-related expenses.

BTD's operating expenses were essentially flat between the quarters.

Depreciation expense increased between the quarters as a result of \$21.3 million in capital additions from October 2005 through September 2006 at all four manufacturing companies. Capital additions at DMI's Ft. Erie plant totaled \$8.0 million over the twelve month period.

Health Services

(in thousands)	Three months ended		Change	%
	2006	September 30, 2005		
Operating revenues	\$ 35,432	\$ 30,653	\$ 4,779	15.6
Cost of goods sold	28,100	21,795	6,305	28.9
Operating expenses	5,686	5,798	(112)	(1.9)
Depreciation and amortization	897	973	(76)	(7.8)
Operating income	\$ 749	\$ 2,087	\$ (1,338)	(64.1)

The increase in health services operating revenues for the three months ended September 30, 2006 compared with the three months ended September 30, 2005 reflects a \$3.4 million increase in revenues from sales and servicing of equipment and sales of supplies and accessories, a \$1.1 million increase in revenues from rentals and interim installations of scanning equipment along with providing technical support services for those rental and interim installations and a \$0.3 million increase in scanning services revenue. A 15.0% increase in the revenue per scan was

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partially offset by an 11.3% decrease in the number of scans performed between the quarters. The increase in health services revenue was more than offset by the increase in health services cost of goods sold, mainly as a result of increases in costs of equipment purchased for resale and increases in unit rental and sublease and maintenance costs. Health services operating expenses decreased mainly as a result of a decrease in compensation expense related to severance paid to a key employee in the third quarter of 2005. The decrease in depreciation and amortization expense is the result of certain assets reaching the ends of their depreciable lives. When these assets are replaced, they are generally replaced with assets leased under operating leases.

Food Ingredient Processing

(in thousands)	Three months ended		Change	%
	September 30,			
	2006	2005		Change
Operating revenues	\$ 11,474	\$ 9,808	\$ 1,666	17.0
Cost of goods sold	11,409	7,625	3,784	49.6
Operating expenses	728	752	(24)	(3.2)
Depreciation and amortization	939	873	66	7.6
Operating (loss) income	\$ (1,602)	\$ 558	\$ (2,160)	(387.1)

The increase in food ingredient processing revenues reflects a 17.2% increase in the sales price per pound of product sold between the quarters while pounds of product sold decreased 0.2% between the quarters. The food ingredient processing segment has been negatively impacted by raw potato supply shortages in Idaho and Prince Edward Island. Higher than expected raw potato costs related to the supply shortages have resulted in operating inefficiencies and a 49.9% increase in the cost per pound of product sold. The increase in depreciation and amortization expense is related to \$1.4 million in capital additions from October 2005 through September 2006.

Other Business Operations

(in thousands)	Three months ended		Change	%
	September 30,			
	2006	2005		Change
Operating revenues	\$ 40,739	\$ 30,805	\$ 9,934	32.2
Cost of goods sold	26,511	20,194	6,317	31.3
Operating expenses	13,840	12,815	1,025	8.0
Depreciation and amortization	748	664	84	12.7
Operating loss	\$ (360)	\$ (2,868)	\$ 2,508	(87.4)

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

Revenues at Foley Company increased \$9.2 million in the third quarter of 2006 compared to the third quarter of 2005 due to an increase in the volume of work performed between the periods.

Revenues at E.W. Wylie Corporation (Wylie) increased \$1.1 million between the quarters due to a 4.8% net increase in miles driven by owner-operated and company-operated trucks. Miles driven by owner-operated trucks increased 45.4% while miles driven by company-operated trucks decreased 14.1%, between the quarters. Wylie's increased revenues also reflect higher rates related to increased fuel costs recovered through fuel surcharges between the periods for both owner-operated and company-operated trucks.

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Revenues at Midwest Construction Services, Inc. (MCS) decreased \$0.3 million between the quarters. The increase in cost of goods sold in the other business operations segment relates to the following:
Foley Company's cost of goods sold increased \$8.1 million mainly in the areas of construction materials, subcontractor and labor and benefit costs as a result of increased volume of work performed between the periods.

Cost of goods sold at MCS decreased \$1.8 million mainly due to a reduction in material and labor costs between the quarters mostly related to a job completed in 2005 which had higher than expected costs. The increase in operating expenses in the other business operations segment is due to the following:
Wylie's revenue increase was offset by a \$1.1 million increase in contractor costs related to higher fuel costs combined with an increase in miles driven by owner-operated trucks between the periods.

Foley Company's operating expenses increased \$0.4 million between the quarters, mainly as a result of increases in compensation costs.

Other operating expenses in this segment decreased \$0.5 million between the quarters mainly related to a gain on the sale of property owned by our subsidiary that owns substantially all of our nonelectric companies.

Income Taxes – Continuing Operations

The \$4.1 million (37.9%) decrease in income taxes – continuing operations between the quarters is primarily the result of a \$9.8 million (32.6%) decrease in income from continuing operations before income taxes for the three months ended September 30, 2006 compared with the three months ended September 30, 2005. The effective tax rate for continuing operations for the three months ended September 30, 2006 was 33.1% compared to 35.9% for the three months ended September 30, 2005. The decrease in the effective tax rate is due to the reduction of \$0.6 million in income tax liabilities in the third quarter of 2006 as a result of closed income tax returns.

Discontinued Operations

Discontinued operations includes the operating results of the gas marketing operation of OTESCO, the Company's energy services company, St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC) for the three months ended September 30, 2005. In June 2006, OTESCO sold its gas marketing operations for \$0.5 million in cash. The Company finalized the sales of SGS and CLC in the third quarter of 2005. Discontinued operations includes a loss from discontinued operations for the three months ended September 30, 2005 and an after-tax gain on the disposition of discontinued operations during the three months ended September 30, 2005 as shown in the table below. OTESCO's gas marketing operations includes a \$1.0 million goodwill impairment loss for the three months ended September 30, 2005.

(in thousands)	OTESCO Gas	Three months ended September 30, 2005		
		SGS	CLC	Total
(Loss) before income taxes	\$ (1,145)	\$ (161)	\$ (677)	\$ (1,983)
Gain on disposition – pretax		44		44
Income tax (benefit)	(57)	(47)	(270)	(374)
Net (loss)	\$ (1,088)	\$ (70)	\$ (407)	\$ (1,565)

Table of ContentsComparison of the Nine Months Ended September 30, 2006 and 2005

Consolidated operating revenues were \$818.3 million for the nine months ended September 30, 2006 compared with \$723.1 million for the nine months ended September 30, 2005. Operating income was \$73.7 million for the nine months ended September 30, 2006 compared with \$75.4 million for the nine months ended September 30, 2005. The Company recorded diluted earnings per share from continuing operations of \$1.31 for the nine months ended September 30, 2006 compared to \$1.39 for the nine months ended September 30, 2005 and total diluted earnings per share from continuing and discontinued operations of \$1.32 for the nine months ended September 30, 2006 compared to \$1.68 for the nine months ended September 30, 2005, which included a net gain of \$0.29 per share from the sales of MIS, SGS and CLC.

Amounts presented in the segment tables that follow for operating revenues, cost of goods sold and other nonelectric operating expenses for the nine month periods ended September 30, 2006 and 2005 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:

<i>(in thousands)</i>	Nine months ended September 30,	
	2006	2005
Operating revenues	\$2,714	\$2,997
Cost of goods sold	1,127	1,663
Other nonelectric expenses	1,587	1,334

Electric

<i>(in thousands)</i>	Nine months ended September 30,		Change	% Change
	2006	2005		
Retail sales revenues	\$ 194,858	\$ 184,328	\$ 10,530	5.7
Wholesale revenues	18,395	31,824	(13,429)	(42.2)
Net marked-to-market gain	144	3,509	(3,365)	(95.9)
Other revenues	13,911	13,742	169	1.2
Total operating revenues	\$ 227,308	\$ 233,403	\$ (6,095)	(2.6)
Production fuel	42,108	40,211	1,897	4.7
Purchased power system use	44,990	44,737	253	0.6
Other operation and maintenance expenses	77,889	72,635	5,254	7.2
Depreciation and amortization	19,234	18,287	947	5.2
Property taxes	7,429	7,816	(387)	(5.0)
Operating income	\$ 35,658	\$ 49,717	\$ (14,059)	(28.2)

The increase in retail electric revenue is due mainly to a \$10.9 million increase in FCA revenues related to increases in fuel and purchased power costs for system use, but also includes \$4.2 million of revenue for uncollected fuel and purchased power costs under a FCA true-up mechanism established by order of the MPUC and \$1.9 million related to the reversal of the refund provision established in December 2005 relating to MISO costs. The Minnesota FCA true-up relates to costs incurred from July 2004 through June 2006 and will be recovered from Minnesota customers from August 2006 through July 2007. On a go-forward basis the electric utility will accrue for the Minnesota FCA true-up on a monthly basis along with its regular monthly FCA accrual. In December 2005, the MPUC issued an order denying recovery of certain MISO related costs through the FCA in Minnesota retail rates and requiring a refund of

amounts previously collected. In February 2006 the MPUC reconsidered its order and eliminated the

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refund requirement. Retail mwh sales increased 2.0% between the periods as a result of increased sales to industrial customers mainly due to increased consumption by pipeline customers as higher oil prices have led to an increase in the volume of product being transported from Canada and the Williston basin. An 8.4% decrease in heating degree days was offset by a 22.5% increase in cooling degree days between the periods, with the net effect of weather having no discernable impact on the variance in mwh sales.

Wholesale sales revenue from company-owned generation increased \$2.3 million in the nine months ended September 30, 2006 compared to the nine months ended September 30, 2005 as a result of a 13.5% increase in mwhs sold combined with a 1.1% increase in the price per mwh sold between the periods. Advance purchases of electricity in anticipation of normal winter weather resulted in increased wholesale electric sales in January 2006 due to unseasonably mild weather. Wholesale sales from company-owned generation were curtailed in February and March 2006 as generation levels were restricted due to coal supply constraints at Big Stone and Hoot Lake plants. Advance purchases of electricity in anticipation of continuing coal supply constraints in the second quarter of 2006 freed up more generation for wholesale sales when coal supplies improved in May 2006. Net revenue from energy trading activities including net mark-to-market gains on forward energy contracts were \$0.6 million for the nine months ended September 30, 2006 compared with \$19.7 million for the nine months ended September 30, 2005. The \$19.1 million decrease in revenue from energy trading activities reflects a \$10.1 million reduction in net profits from virtual transactions, a \$6.4 million reduction in profits from purchased power resold and a \$3.4 million decrease in net mark-to-market gains on forward energy contracts, offset by a \$0.7 increase in profits from the purchase and sale of financial transmission rights. Profits from virtual transactions were \$10.8 million in the first nine months of 2005 compared to \$0.7 million in the first nine months of 2006 as the MISO market has matured and become more efficient and as a result of a reduction in virtual transactions due to uncertainties related to the status of RSG charges in MISO's Transmission and Energy Markets Tariff. In the first nine months of 2006 the Company recorded a net loss on purchased power resold of \$2.1 million compared to a net gain of \$4.3 million in the first nine months of 2005. Of the \$2.9 million in net mark-to-market gains recognized on open forward energy contracts at December 31, 2005, \$2.1 million was realized and \$0.8 million was reversed in the first nine months of 2006 as market prices on forward electric contracts declined in response to decreased demand for electricity due, in part, to regional winter weather that was milder than expected.

The increase in fuel costs for the nine months ended September 30, 2006 compared with the nine months ended September 30, 2005 reflects a 4.4% increase in the cost of fuel per mwh generated combined with a 0.3% increase in mwhs generated. Generation used for wholesale electric sales increased 13.5% while generation for retail sales decreased 2.0% between the periods. Fuel costs per mwh increased at the Coyote Station and Hoot Lake Plant as a result of increases in coal costs and coal transportation costs between the periods. Much of the increase in coal costs and coal transportation costs is directly related to higher diesel fuel prices. The mix of available generation resources in the first nine months of 2006 compared to the first nine months of 2005 was also a contributing factor to the increase in the cost of fuel per mwh generated. Big Stone Plant's generation increased 14.0% between the periods while Coyote Station's generation was down 11.4%. In the second quarter of 2006, Coyote Station, our lowest cost base-load plant, was off-line for five weeks for scheduled maintenance. In the second quarter of 2005, the higher-cost Big Stone Plant was shutdown for seven weeks for scheduled maintenance. Approximately 90% of the fuel cost increases associated with generation to serve retail electric customers is subject to recovery through the fuel cost recovery component of retail rates.

The increase in purchased power system use (to serve retail customers) is due to a 14.2% increase in the cost per mwh purchased mostly offset by an 11.9% reduction in mwh purchases for system use.

The increase in other operation and maintenance expenses for the nine months ended September 30, 2006 compared with the nine months ended September 30, 2005 resulted primarily from \$1.9 million in increased operating and maintenance costs at the electric utility's generation plants, including Coyote Station, which was shut down for five weeks of scheduled maintenance in the second quarter of 2006, \$1.4 million in increased costs related to contract work performed for other area utilities and \$1.5 million from increases in tree-trimming costs

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and dues and subscriptions, legal, advertising and miscellaneous office expenses.

Depreciation expense increased in the nine months ended September 30, 2006 compared with the nine months ended September 30, 2005 as a result of a \$20.6 million increase in electric plant in service in 2005.

The \$0.4 million decrease in property taxes reflects lower property valuations used for determining 2006 property taxes in Minnesota and South Dakota.

Plastics

(in thousands)	Nine months ended		Change	% Change
	2006	September 30, 2005		
Operating revenues	\$ 136,731	\$ 113,621	\$ 23,110	20.3
Cost of goods sold	103,794	92,765	11,029	11.9
Operating expenses	6,790	4,943	1,847	37.4
Depreciation and amortization	2,101	1,848	253	13.7
Operating income	\$ 24,046	\$ 14,065	\$ 9,981	71.0

The increase in operating revenues for the plastics segment between the periods reflects a 24.1% increase in the price per pound of PVC and PE pipe sold offset by a 3.2% decrease in pounds of pipe sold. The increase in prices reflects the effect of a 16.3% increase in resin costs per pound of PVC pipe shipped between the periods. The decrease in pounds of pipe sold is due to a decrease in sales in the third quarter of 2006 compared with the third quarter of 2005. The increase in cost of goods sold is a result of higher resin costs. The increase in plastics segment operating expenses reflects increased sales, general and administrative expenses directly related to the increases in revenue and operating income between the periods. The increase in depreciation and amortization expense is related to capital additions from October 2005 through September 2006, mainly for production equipment.

Manufacturing

(in thousands)	Nine months ended		Change	% Change
	2006	September 30, 2005		
Operating revenues	\$ 226,555	\$ 183,190	\$ 43,365	23.7
Cost of goods sold	178,970	145,952	33,018	22.6
Operating expenses	19,668	16,247	3,421	21.1
Depreciation and amortization	8,124	7,047	1,077	15.3
Operating income	\$ 19,793	\$ 13,944	\$ 5,849	41.9

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

Revenues at DMI increased \$39.7 million as a result of increases in production and sales activity due in part to plant additions, including initial operations at the Ft. Erie facilities, and continued improvements in productivity and capacity utilization.

Revenues at ShoreMaster increased \$3.6 million between the periods due to the acquisition of Southeast Floating Docks in May 2005 and price increases driven by higher material costs, especially aluminum.

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Revenues at T.O. Plastics increased \$1.1 million between the periods as a result of a 1.9% increase in unit sales combined with an 11.6% increase in revenue per unit sold.

Revenues at BTD decreased \$1.0 million mainly as a result of a 6.9% decrease in units sold between the periods. The increase in cost of goods sold in our manufacturing segment relates to the following:

DMI's cost of goods sold increased \$32.2 million between the periods, including increases of \$24.1 million in material costs, \$5.9 million in labor and benefit costs and \$2.0 in tools and supplies expenditures. The increase in cost of goods sold is directly related to the increase in DMI's production and sales activity and start up costs at its Ft. Erie facilities.

Cost of goods sold at ShoreMaster increased \$2.6 million between the periods as a result of increases in labor, material (especially aluminum) and other direct costs and the acquisition of Southeast Floating Docks in May 2005.

Cost of goods sold at T.O. Plastics increased \$1.4 million, reflecting \$1.1 million in material cost increases and \$0.4 million in increased labor costs between the periods related to a 1.9% increase in unit sales.

Cost of goods sold at BTD decreased \$3.4 million between the periods due to a \$2.1 million decrease in material costs and a \$1.4 million decrease in labor costs between the periods. The decrease in material costs is related to a 6.9% decrease in unit sales. The decrease in labor costs is related to a reduction in the number of production employees and a decrease in overtime pay between the periods. Productivity gains at BTD were achieved through efforts to better utilize and allocate available labor resources.

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

Operating expenses at DMI increased \$1.9 million as a result of increases in labor, professional services and maintenance expenses mainly related to start-up costs at the Ft. Erie plant.

ShoreMaster's operating expenses increased \$0.7 million as a result of increases in bad debt and sales related expenses.

An increase in incentive accruals contributed to a \$0.4 million increase in BTD's operating expenses between the periods.

T.O. Plastics operating expenses increased \$0.4 million due to a reduction in gains on sales of fixed assets related to fixed asset sales in the second quarter of 2005 and increases in labor and payroll tax expenses.

Depreciation expense increased between the periods as a result of \$21.1 million in capital additions from October 2005 through September 2006 at all four manufacturing companies. Capital additions at DMI's Ft. Erie plant totaled \$8.0 million over the twelve month period.

Table of Contents**Health Services**

(in thousands)	Nine months ended		Change	% Change
	2006	September 30, 2005		
Operating revenues	\$ 100,341	\$ 89,775	\$ 10,566	11.8
Cost of goods sold	78,147	64,882	13,265	20.4
Operating expenses	16,768	15,983	785	4.9
Depreciation and amortization	2,733	3,050	(317)	(10.4)
Operating income	\$ 2,693	\$ 5,860	\$ (3,167)	(54.0)

The increase in health services operating revenues for the nine months ended September 30, 2006 compared with the nine months ended September 30, 2005 reflects a \$6.6 million increase in imaging revenues combined with a \$4.0 million increase in revenues from sales and servicing of diagnostic imaging equipment. On the imaging side of the business, \$3.5 million of the \$6.6 million increase in revenue came from imaging services where the revenue per scan increased 14.9% between the periods while the number of scans completed decreased 7.0%. Revenues from rentals and interim installations of scanning equipment along with providing technical support services for those rental and interim installations increased \$3.1 million between the periods. The increase in health services revenue was more than offset by the increase in health services cost of goods sold, mainly as a result of increases in costs of equipment purchased for resale, increases in unit rental and sublease costs related to units that were out of service in the first six months of 2006 and increases in labor and other direct costs. The increase in operating expenses is mainly due to increases in travel and property tax expenses. The decrease in depreciation and amortization expense is the result of certain assets reaching the ends of their depreciable lives. When these assets are replaced, they are generally replaced with assets leased under operating leases.

Food Ingredient Processing

(in thousands)	Nine months ended		Change	% Change
	2006	September 30, 2005		
Operating revenues	\$ 30,635	\$ 27,297	\$ 3,338	12.2
Cost of goods sold	30,419	20,731	9,688	46.7
Operating expenses	2,203	1,831	372	20.3
Depreciation and amortization	2,805	2,519	286	11.4
Operating (loss) income	\$ (4,792)	\$ 2,216	\$ (7,008)	(316.2)

The increase in food ingredient processing revenues reflects a 12.7% increase in sales price per pound of product sold slightly offset by a 0.4% decrease in pounds sold between the periods. The food ingredient processing segment has been negatively impacted by raw potato supply shortages in Idaho and Prince Edward Island. Higher than expected raw product costs related to the supply shortages have resulted in operating inefficiencies and a 47.4% increase in the cost per pound of product sold. The increase in operating expenses is due to an increase in selling and administrative expenses between the periods.

Table of Contents**Other Business Operations**

(in thousands)	Nine months ended September 30,		Change	% Change
	2006	2005		
Operating revenues	\$ 99,397	\$ 78,781	\$ 20,616	26.2
Cost of goods sold	59,702	50,227	9,475	18.9
Operating expenses	41,255	37,042	4,213	11.4
Depreciation and amortization	2,158	1,907	251	13.2
Operating loss	\$ (3,718)	\$ (10,395)	\$ 6,677	(64.2)

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

Revenues at Foley Company increased \$20.3 million in the first nine months of 2006 compared to the first nine months of 2005 due to an increase in the volume of work performed between the periods.

Revenues at Wylie increased \$3.8 million between the periods mainly due to a 6.8% net increase in miles driven by owner-operated and company-operated trucks. Miles driven by owner-operated trucks increased 51.9% while miles driven by company-operated trucks decreased 11.2% between the periods. Wylie's increased revenues also reflect higher rates related to increased fuel costs recovered through fuel surcharges between the periods for both owner-operated and company-operated trucks.

Revenues at MCS decreased \$3.4 million between the periods as a result of a delay on the start-up of several wind projects. Selected projects had been delayed nationwide due to Federal Aviation Administration actions related to possible radar issues.

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

Foley Company's cost of goods sold increased \$17.1 million mainly in the areas of materials, subcontractor and labor costs as a result of an increase in the volume of work performed between the periods.

Cost of goods sold at MCS decreased \$7.6 million mainly due to a reduction in material and labor costs between the periods mostly related to a job completed in 2005 on which large losses were incurred as a result of higher than expected costs.

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

Wylie's revenue increase was entirely offset by a \$3.8 million increase in operating expenses, including \$3.4 million in contractor costs related to higher fuel costs combined with an increase in miles driven by owner-operated trucks between the periods and \$0.4 million in increased insurance costs.

Foley Company's operating expenses increased \$0.8 million between the periods as a result of increases in compensation costs.

MCS operating expenses increased \$0.3 million between the periods, mainly due to increases in salary and benefit expenses.

Operating expenses in this segment decreased \$0.7 million mainly related to a gain on the sale of property owned by our subsidiary that owns substantially all of our nonelectric companies.

Table of Contents**Income Taxes – Continuing Operations**

The effective tax rate for continuing operations for the nine months ended September 30, 2006 was 35.5% compared to 34.5% for the nine months ended September 30, 2005. The increase in the effective tax rate is related to a \$0.5 million write-down of deferred tax assets in the second quarter of 2006 related to the expected expiration of operating loss carryforwards at the end of 2006 at the Canadian operations of Idaho Pacific Holdings, Inc. (IPH) and a change in estimate in the reversal of regulatory deferred tax liabilities at the electric utility, mostly offset by a \$0.6 million reduction in income tax expense in the third quarter of 2006 related to the reduction of income tax liabilities as a result of closed income tax returns.

Discontinued Operations

Discontinued operations includes the operating results of the gas marketing operation of OTESCO, the Company's energy services company, for the nine month periods ended September 30, 2006 and 2005 and of MIS, SGS and CLC for the nine month period ended September 30, 2005. In June 2006, OTESCO sold its gas marketing operations for \$0.5 million in cash. The Company completed the sales of MIS, SGS and CLC in 2005. Discontinued operations include net income (loss) from discontinued operations for the nine month periods ended September 30, 2006 and 2005 and net after-tax gains and losses on the disposition of discontinued operations in the nine month periods ended September 30, 2006 and 2005 as shown in the table below. OTESCO's gas marketing operations includes a \$1.0 million goodwill impairment loss for the nine months ended September 30, 2005.

(in thousands)	Nine months ended September 30, 2006		Nine months ended September 30, 2005			
	OTESCO Gas	OTESCO Gas	MIS	SGS	CLC	Total
Income (loss) before income taxes	\$ 54	\$ (1,163)	\$ 2,167	\$ (1,724)	\$ (696)	\$ (1,416)
Gain (loss) on disposition pretax	560		19,025	(3,002)	(300)	15,723
Income tax expense (benefit)	252	(64)	7,975	(1,890)	(396)	5,625
Net income (loss)	\$ 362	\$ (1,099)	\$ 13,217	\$ (2,836)	\$ (600)	\$ 8,682

2006 OUTLOOK

The statements in this section are based on our current outlook for 2006 and are subject to risks and uncertainties described under "Forward Looking Information – Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995."

We reaffirm our guidance to be in the range of \$1.55 to \$1.75 of diluted earnings per share from continuing operations. Items contributing to the current earnings guidance for 2006 are as follows:

Due to the coal supply issues late in the first quarter and early second quarter of 2006, decreasing margins on wholesale energy sales involving the purchase and sale of electric energy contracts and increasing transmission and wage and benefit costs, we expect earnings in the electric segment in 2006 to be in a range of \$26.5 million to \$28.0 million which is consistent with 2006 second quarter expectations.

We expect plastics segment earnings to be slightly higher in 2006 compared to 2005 levels due to the strong performance during the first nine months of 2006.

Our forecasted 2006 net income from the manufacturing segment is in line with initial 2006 expectations. The improving economy, continued enhancements in productivity and capacity utilization, expanded markets, and expansion of production capacity with the opening of a new wind tower production facility in Ft. Erie, Ontario, Canada, are expected to result in increased net income in our manufacturing segment in 2006.

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Our health services segment is expected to have earnings in the range of \$1.7 million to \$2.3 million in 2006 due to the lower than expected results in the first nine months of 2006.

We expect to record a net loss in the range of \$1.6 million to \$3.4 million from our food ingredient processing business in 2006. This is consistent with 2006 second quarter expectations.

Our other business operations segment is expected to show improved results over 2005, consistent with our expectations at the beginning of 2006, due to an improving economy and an increase in backlog of construction contracts. An increase in wind energy projects activity is expected to have a positive impact on our electrical contracting business.

FINANCIAL POSITION

For the period 2006 through 2010, we estimate funds internally generated net of forecasted dividend payments will be sufficient to meet scheduled debt retirements (excluding the scheduled retirement of the \$50 million 6.375% senior debentures due December 1, 2007), to repay currently outstanding short-term debt and to provide for our estimated consolidated capital expenditures (excluding expenditures related to the proposed generating unit at the Big Stone Plant site). Reduced demand for electricity, reductions in wholesale sales of electricity or margins on wholesale sales, or declines in the number of products manufactured and sold by our companies could have an effect on funds internally generated. Additional equity or debt financing will be required in the period 2006 through 2010 in the event we decide to refund or retire early any of our presently outstanding debt or cumulative preferred shares, to retire the \$50 million 6.375% senior debentures due December 1, 2007, to complete acquisitions, to fund the construction of the proposed generating unit at the Big Stone Plant site or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

During the first nine months of 2006 the Company issued 85,223 common shares for stock options exercised and 1,727 common shares for director's compensation and retired 16,370 common shares for tax withholding purposes related to restricted shares that vested in March and April 2006.

We have the ability to issue up to \$256 million of common stock, preferred stock, debt and certain other securities from time to time under our universal shelf registration statement filed with the Securities and Exchange Commission. On April 26, 2006 we renewed our line of credit with U.S. Bank National Association, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, Harris Nesbitt Financing, Inc., Keybank National Association, Union Bank of California, N.A., Bank of America, N.A., Bank Hapoalim B.M., and Bank of the West and increased the amount available under the line from \$100 million to \$150 million. The renewed agreement expires on April 26, 2009. The terms of the renewed line of credit are essentially the same as those in place prior to the renewal. However, outstanding letters of credit issued by the Company can reduce the amount available for borrowing under the line by up to \$30 million and we can increase our commitments under the renewed line of credit up to \$200 million. Borrowings under the line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of our senior unsecured debt. This line is an unsecured revolving credit facility available to support borrowings of our nonelectric operations. Our obligations under this line of credit are guaranteed by a 100%-owned subsidiary that owns substantially all of our nonelectric companies. As of September 30, 2006, \$50.0 million of the \$150 million line of credit was in use and \$18.3 million was restricted from use to cover outstanding letters of credit.

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On September 1, 2006, the Company entered into a \$25 million Credit Agreement (Credit Agreement) with U.S. Bank National Association. The Credit Agreement creates an unsecured revolving credit facility the Company can draw on to support the working capital needs and other capital requirements of the Company's electric operations. The Credit Agreement expires on September 1, 2007. Borrowings under the line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of the Company's senior unsecured debt. The Credit Agreement contains terms that are substantially the same as those under the \$150 million unsecured credit facility dated April 26, 2006. As of September 30, 2006, \$4.0 million of this \$25 million line of credit was in use. The electric utility also had \$6.6 million invested in short-term investments that mature in 90 days or less which are classified as cash equivalents on the Company's consolidated balance sheet as of September 30, 2006.

Our lines of credit, \$90 million 6.63% senior notes and Lombard US Equipment Finance note contain the following covenants: a debt-to-total capitalization ratio not in excess of 60% and an interest and dividend coverage ratio of at least 1.5 to 1. The 6.63% senior notes also require that priority debt not be in excess of 20% of total capitalization. We were in compliance with all of the covenants under our financing agreements as of September 30, 2006.

Our obligations under the 6.63% senior notes are guaranteed by our 100%-owned subsidiary that owns substantially all of our nonelectric companies. Our Grant County and Mercer County pollution control refunding revenue bonds and our 5.625% insured senior notes require that we grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds and notes, a security interest in the assets of the electric utility if the rating on our senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's).

Our current securities ratings are:

	Moody's Investors Service	Standard & Poor's
Senior unsecured debt	A3	BBB+
Preferred stock	Baa2	BBB-
Outlook	Stable	Stable

Our disclosure of these securities ratings is not a recommendation to buy, sell or hold our securities. Downgrades in these securities ratings could adversely affect our company. Further downgrades could increase borrowing costs resulting in possible reductions to net income in future periods and increase the risk of default on our debt obligations. Cash provided by operating activities for continuing operations was \$42.7 million for the nine months ended September 30, 2006 compared with cash provided by operating activities from continuing operations of \$39.1 million for the nine months ended September 30, 2005. The \$3.6 million increase in cash provided by operating activities from continuing operations reflects the non-cash impact on net income of a \$6.3 million change in net derivative assets related to forward energy contracts from a \$2.9 million increase in the first nine months of 2005 to a \$3.4 million decrease in net derivative assets in the first nine months of 2006, offset by a \$1.7 million decrease in net income from continuing operations and \$1.1 million increase in cash used for working capital items between the periods.

Major uses of funds for working capital items in the first nine months of 2006 were an increase in other current assets of \$19.3 million, an increase in inventories of \$17.7 million, an increase in receivables of \$9.1 million and a decrease in interest and income taxes payable of \$3.8 million, offset by a \$12.2 million increase in accounts payable and other current liabilities. The increase in other current assets includes an increase of \$21.8 million in costs in excess of billings at DMI mainly related to wind tower production to fill a large order that extends into 2007. While a

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number of units in this order have been completed, the terms of the contract specify that the customer, who has a strong senior unsecured debt rating, will not be billed until the units are shipped. The increase in costs in excess of billings at DMI was slightly offset by decreases in costs in excess of billings of \$1.1 million at Foley Company and \$1.0 million at ShoreMaster. DMI's inventories increased \$6.0 million in the first nine months of 2006 as a result of increases in raw material costs and in response to increased demand for wind towers. Inventories at our plastic pipe companies increased \$4.4 million. Inventories at the electric utility increased \$3.1 million, of which \$1.3 million relates to a build up of coal stockpiles at Big Stone and Hoot Lake plants since year-end 2005 and \$1.8 million relates to increase in materials and supplies inventory. Our construction companies' inventories increased \$2.6 million mostly related to a build up of electronic surveillance and security products at MCS. Our food ingredient processing companies' inventories increased \$0.6 million mainly as a result of increases in raw material costs (prices paid for process-grade potatoes). Health services inventories are up \$0.6 million from the beginning of 2006. The \$9.1 million increase in receivables includes \$8.9 million at Foley Company related to increased construction activity and \$7.9 million at DMI related to increasing sales of wind towers, offset by a \$4.9 million seasonal reduction in receivables at our electric utility company and a \$2.9 million reduction in receivables at ShoreMaster.

Net cash used in investing activities of continuing operations was \$53.2 million for the nine months ended September 30, 2006 compared to \$46.1 million for the nine months ended September 30, 2005. Cash used for capital expenditures increased by \$11.1 million between the periods. Cash used for capital expenditures at the electric utility increased by \$5.7 million mainly for replacement of assets damaged in the November 2005 ice storm and for expenditures related to the proposed generating unit at our Big Stone Plant site. Cash used for capital expenditures in the manufacturing segment increased by \$5.0 million between the periods mainly at DMI in connection with the start up of its Ft. Erie plant. We invested \$11.2 million in cash, net of cash acquired, in the acquisitions of Performance Tool & Die, Shoreline and Southeast Floating Docks in the first nine months of 2005. We made no acquisition expenditures in the first nine months of 2006.

Net cash provided by financing activities from continuing operations was \$10.6 million in the nine months ended September 30, 2006 compared with net cash used in financing activities from continuing operations of \$27.1 million the nine months ended September 30, 2005 mainly due to a \$43.0 million increase in short-term borrowings and checks issued in excess of cash between the periods offset by a \$6.6 million decrease in proceeds from the issuance of common stock. The decrease in proceeds from the issuance of common stock reflects the issuance of common stock related to the partial exercise of the underwriters' over-allotment option in January 2005 and a decrease in stock options exercised between the periods. Payments for the retirement of long-term debt decreased by \$2.8 million between the periods. The \$0.3 million increase in cash paid for debt issuance expenses between the periods relates to the renegotiation and three-year extension of our line-of-credit agreement in April 2006. The \$0.9 million increase in dividends paid between the periods is due to an increase in dividends paid per common share in 2006 and the issuance of additional common shares between the periods.

There were changes in our contractual obligations in the third quarter of 2006 from those reported under the caption

Capital Requirements on page 24 of our 2005 Annual Report to Shareholders. These changes include purchase obligations related to a portion of IPH's raw potato supply requirements for the 2006-2007 processing season of approximately \$4.5 million in 2006 and \$8.8 million in 2007, and a new 15-year rail-car lease arrangement entered into by the electric utility that will increase operating lease obligations by \$0.1 million in 2006, \$0.7 million in 2007 and 2008 combined, \$0.7 million in 2009 and 2010 combined and \$3.9 million in the years beyond 2010.

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

Critical Accounting Policies Involving Significant Estimates

The discussion and analysis of the financial statements and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the

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United States of America. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities.

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, valuation of forward energy contracts, unbilled electric revenues, unscheduled power exchanges, MISO electric market residual load adjustments, service contract maintenance costs, percentage-of-completion, valuation of stock-based payments and actuarially determined benefits costs. 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.

Goodwill Impairment

We currently have \$24.2 million of goodwill recorded on our balance sheet related to the acquisition of IPH in 2004. If current conditions of low sales volumes and prices, increasing raw material costs and the increasing value of the Canadian dollar relative to the U.S. dollar persist and operating margins do not improve according to our projections, the reductions in anticipated cash flows from this business may indicate that its fair value is less than its book value resulting in an impairment of goodwill and a corresponding charge against earnings.

We evaluate goodwill for impairment on an annual basis and as conditions warrant. As of December 31, 2005 an assessment of the carrying values of our goodwill indicated no impairment.

A discussion of critical accounting policies is included under the caption Critical Accounting Policies Involving Significant Estimates on pages 30 through 32 of our 2005 Annual Report to Shareholders. There were no material changes in critical accounting policies or estimates during the quarter ended September 30, 2006.

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 are intended to identify forward-looking statements within the meaning of the Act and are included, along with this statement, for purposes of complying with the safe harbor provision of the Act.

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

We are subject to government regulations and actions that may have a negative impact on our business and results of operations.

Certain MISO-related costs currently included in the FCA in Minnesota retail rates may be excluded from recovery through the FCA and subject to future recovery through rates established in a general rate case.

Weather conditions can adversely affect our operations and revenues.

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Electric wholesale trading margins could be reduced or eliminated by losses due to trading activities.

Wholesale sales of electricity from excess generation could be reduced by reductions in coal shipments to Big Stone and Hoot Lake plants due to supply constraints or rail transportation problems beyond our control.

Our electric segment has capitalized \$4.6 million in costs related to the planned construction of a second electric generating unit at its Big Stone Plant site as of September 30, 2006. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods would be subject to expense and may not be recoverable.

Our manufacturer of wind towers operates in a market that has been dependent on the Production Tax Credit. This tax credit is currently in place through December 31, 2007. Should this tax credit not be renewed, the revenues and earnings of this business could be reduced.

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

Our plans to grow and diversify through acquisitions may not be successful and could result in poor financial performance.

Competition is a factor in all of our businesses.

Economic uncertainty could have a negative impact on our future revenues and earnings.

Volatile financial markets could restrict our ability to access capital and could increase borrowing costs and pension plan expenses.

Our food ingredient processing segment operates in a highly competitive market and is dependent on adequate sources of raw materials for processing. Should the supply of these raw materials be affected by poor growing conditions, this could negatively impact the results of operations for this segment. This segment could also be impacted by foreign currency changes between Canadian and United States currency and prices of natural gas.

Our plastics segment is highly dependent on a limited number of vendors for PVC resin. In the first nine months of 2006, 99% of resin purchased was from two vendors, 52% from one and 47% from the other. The loss of a key vendor or an interruption or delay in the supply of PVC resin could result in reduced sales or increased costs for this business. Reductions in PVC resin prices could negatively impact PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.

Our health services businesses may not be able to retain or comply with the dealership arrangement and other agreements with Philips Medical.

For a further discussion of other risk factors and cautionary statements, refer to Risk Factors and Cautionary Statements and Critical Accounting Policies Involving Significant Estimates on pages 26 through 32 of our 2005 Annual Report to Shareholders. These factors are in addition to any other cautionary statements, written or oral, which may be made or referred to in connection with any such forward-looking statement or contained in any subsequent filings by the Company with the Securities and Exchange Commission.

Table of Contents**Item 3. Quantitative and Qualitative Disclosures About Market Risk**

At September 30, 2006 we had limited exposure to market risk associated with interest rates and commodity prices and limited exposure to market risk associated with changes in foreign currency exchange rates. Outstanding trade accounts receivable of the Canadian operations of IPH are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 36% of IPH sales are outside the United States and the Canadian operations of IPH pays its operating expenses in Canadian dollars.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. In April 2006, we negotiated a fixed rate of 6.76% on our Lombard US Equipment Finance note (the Lombard note) over the remaining term of the note that has a final payment due on October 2, 2010. As of September 30, 2006 we had \$10.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on September 30, 2006, annualized interest expense and pretax earnings would change by approximately \$104,000.

We have not used interest rate swaps to manage net exposure to interest rate changes related to our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

The plastics companies are exposed to market risk related to changes in commodity prices for PVC resins, the raw material used to manufacture PVC pipe. The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower. Gross margins also decline when the supply of PVC pipe increases faster than demand. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or to assume that historical trends will continue.

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of September 30, 2006 the electric utility had recognized, on a pretax basis, \$3,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value the electric utility's forward contracts for the purchases and sales of electricity are determined by survey of counterparties by the electric utility's power services personnel responsible for contract pricing and are benchmarked to regional hub prices as published in *Megawatt Daily* and as observed in the Intercontinental Exchange trading system. Of the forward energy contracts that are marked-to-market as of September 30, 2006, 88% of the forward sales of electricity had offsetting purchases in terms of volumes and delivery periods. The amount of net unrealized marked-to-market gains recognized on forward purchases of electricity not offset by forward sales of electricity as of September 30, 2006 was \$297,000.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. With the advent of the MISO Day 2 market in April 2005, several changes were made to the energy risk management policy to recognize new trading opportunities created by this new market. Most of the changes were in new volumetric

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limits and loss limits to adequately manage the risks associated with these new opportunities. In addition, a Value at Risk (VaR) limit was also implemented to further manage market price risk. Exposure to price risk on any open positions as of September 30, 2006 was not material.

The following tables show the effect of marking-to-market forward contracts for the purchase and sale of electricity on our consolidated balance sheet as of September 30, 2006 and the change in our consolidated balance sheet position from December 31, 2005 to September 30, 2006:

(in thousands)	September 30, 2006
Current asset marked-to-market gain	\$ 5,069
Regulatory asset deferred marked-to-market loss	1,722
Total assets	6,791
Current liability marked-to-market loss	(5,065)
Regulatory liability deferred marked-to-market gain	(1,723)
Total liabilities	(6,788)
Net fair value of marked-to-market energy contracts	\$ 3

(in thousands)	Year-to-date September 30, 2006
Fair value at beginning of year	\$ 2,916
Amount realized on contracts entered into in 2005 and settled in 2006	(2,090)
Changes in fair value of contracts entered into in 2005	(826)
Net fair value of contracts entered into in 2005 at end of period	3
Changes in fair value of contracts entered into in 2006	3
Net fair value end of period	\$ 3

The \$3,000 recognized but unrealized net gain on the forward energy purchases and sales marked to market on September 30, 2006 is expected to be realized on physical settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	4th Quarter 2006	1st Quarter 2007	Total
Net (loss) gain	\$ (5)	\$ 8	\$3

We have credit risk associated with the nonperformance or nonpayment by counterparties to our forward energy purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty's financial strength. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of September 30, 2006 was \$2.3 million. As of September 30, 2006 we had a net credit risk exposure of \$5.2 million from 14 counterparties with investment grade credit ratings. We have no exposure at September 30, 2006 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 \$5.2 million credit risk exposure includes net amounts due to the electric utility on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after September 30, 2006. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

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IPH has market risk associated with the price of fuel oil and natural gas used in its potato dehydration process as IPH may not be able increase prices for its finished products to recover increases in fuel costs. In the third quarter of 2006, IPH entered into forward natural gas contracts on the New York Mercantile Exchange market to hedge its exposure to fluctuations in natural gas prices related to approximately 50% of its anticipated natural gas needs through March 2007 for its Ririe, Idaho and Center, Colorado dehydration plants. These forward contracts are derivatives subject to mark-to-market accounting that qualify as cash flow hedges with unrealized gains and losses being recognized as components of other comprehensive income. On settlement, realized gains and losses are recognized as components of fuel expense in cost of goods sold.

The following tables show the effect of marking-to-market IPH's forward natural gas swaps on our consolidated balance sheet as of September 30, 2006:

(in thousands)	September 30, 2006
Current asset marked-to-market gain	\$
Current liability marked-to-market loss	(452)
Total liabilities	(452)
Net fair value of marked-to-market energy contracts	\$ (452)

IPH recorded \$3,000 in realized gains on forward natural gas contracts that settled in the third quarter of 2006. The \$452,000 unrealized loss on the forward natural gas swaps marked to market on September 30, 2006 are scheduled for settlement over the following quarters in the amounts listed:

(in thousands)	4th Quarter 2006	1st Quarter 2007	Total
Net (loss)	\$(236)	\$(216)	\$(452)

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 of September 30, 2006, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2006.

During the fiscal quarter ended September 30, 2006, 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 has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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 that the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under the caption "Risk Factors and Cautionary Statements" on pages 26 through 28 of the Company's 2005 Annual Report to Shareholders, which is incorporated by reference to Part I, Item 1A, "Risk Factors" in the Company's Annual Report on Form 10-K for the year ended December 31, 2005, except that the first risk factor under the heading "Electric" has been revised as set forth below to reflect that wholesale electric margins have been reduced in connection with the increased efficiency of the MISO market and to reflect an increase in capitalized costs related to the planned construction of a second electric generating unit at the Company's Big Stone Plant site:

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

A number of factors, many of which are beyond our control, may contribute to fluctuations in our revenues and expenses from electric operations, causing our net income to fluctuate from period to period. These risks include fluctuations in the volume and price of sales of electricity to customers or other utilities, which may be affected by factors such as mergers and acquisitions of other utilities, geographic location of other utilities, transmission costs (including increased costs related to operations of regional transmission organizations), changes in the manner in which wholesale power is sold and purchased, unplanned interruptions at our generating plants, the effects of regulation and legislation, demographic changes in our customer base and changes in our customer demand or load growth. Electric wholesale margins have been significantly and adversely affected by increased efficiencies in the MISO market. Electric wholesale trading margins could also be adversely affected by losses due to trading activities. Other risks include weather conditions (including severe weather that could result in damage to our assets), fuel and purchased power costs and the rate of economic growth or decline in our service areas. A decrease in revenues or an increase in expenses related to our electric operations may reduce the amount of funds available for our existing and future businesses, which could result in increased financing requirements, impair our ability to make expected distributions to shareholders or impair our ability to make scheduled payments on our debt obligations. As of September 30, 2006, we had capitalized \$4.6 million in costs related to the planned construction of a second electric generating unit at our Big Stone Plant site. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods would be subject to expense and may not be recoverable.

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Item 6. Exhibits

- 4.1 Credit Agreement, dated as of September 1, 2006, between Otter Tail Corporation dba Otter Tail Power Company and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to the Company's Form 8-K filed September 6, 2006)

- 10.1 Amendment No. 1 to Joint Facilities Agreement, dated July 13, 2006, by and among Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation, dba NorthWestern Energy, Otter Tail Corporation dba Otter Tail Power Company, Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency, as Owners, amending the Joint Facilities Agreement, dated as of June 30, 2005, by and among the Owners (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed August 25, 2006)

- 10.2 Amendment No. 2 to Participation Agreement, dated as of August 18, 2006, by and among the Owners, amending the Participation Agreement, dated as of June 30, 2005, by and among the Owners (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed August 31, 2006)*

- 10.3 Amendment No. 3 to Participation Agreement, effective September 1, 2006, by and among the Owners, amending the Participation Agreement, dated as of June 30, 2005, by and among the Owners (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed October 11, 2006)

- 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

* 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 and
Treasurer
(Chief Financial Officer/Authorized
Officer)

Dated: November 9, 2006

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