OTTER TAIL CORP
Form 10-Q
November 09, 2007

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

(Mark One)

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

For the quarterly period ended September 30, 2007

OR

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

For the transition period from __________ to __________

Commission file number 0-368

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 þ NO o

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 þ Accelerated filer o Non-accelerated filer o

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

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

October 31, 2007 29,847,515 Common Shares ($5 par value)

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2007	December 31, 2006
	(Thousands of dollars)	
Current assets		
Cash and cash equivalents	$ 704	$ 6,791
Accounts receivable:		
Trade net	161,684	135,011
Other	12,713	10,265
Inventories	97,757	103,002
Deferred income taxes	8,221	8,069
Accrued utility revenues	12,693	23,931
Costs and estimated earnings in excess of billings	44,055	38,384
Other	13,637	9,611
Assets of discontinued operations		289
Total current assets	351,464	335,353
Investments and other assets	32,959	29,946
Goodwill net	99,242	98,110
Other intangibles net	20,698	20,080
Deferred debits		
Unamortized debt expense and reacquisition premiums	5,813	6,133
Regulatory assets and other deferred debits	46,882	50,419
Total deferred debits	52,695	56,552
Plant		
Electric plant in service	946,727	930,689
Nonelectric operations	255,913	239,269
Total plant	1,202,640	1,169,958
Less accumulated depreciation and amortization	503,295	479,557
Plant net of accumulated depreciation and amortization	699,345	690,401
Construction work in progress	86,621	28,208
Net plant	785,966	718,609
Total	$ 1,343,024	$ 1,258,650

See accompanying notes to consolidated financial statements

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

	September 30, 2007	December 31, 2006
	(Thousands of dollars)	
Current liabilities		
Short-term debt	$ 78,781	$ 38,900
Current maturities of long-term debt	3,019	3,125
Accounts payable	111,550	120,195
Accrued salaries and wages	26,660	28,653
Accrued federal and state income taxes	4,308	2,383
Other accrued taxes	10,075	11,509
Other accrued liabilities	13,843	10,495
Liabilities of discontinued operations		197
Total current liabilities	248,236	215,457
Pensions benefit liability	42,260	44,035
Other postretirement benefits liability	33,335	32,254
Other noncurrent liabilities	21,581	18,866
Deferred credits		
Deferred income taxes	114,843	112,740
Deferred investment tax credit	7,328	8,181
Regulatory liabilities	64,614	63,875
Other	255	281
Total deferred credits	187,040	185,077
Capitalization		
Long-term debt, net of current maturities	278,378	255,436
Class B stock options of subsidiary	1,255	1,255
Cumulative preferred shares authorized 1,500,000 shares without par value; outstanding 2007 and 2006 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 2007 29,827,870 and 2006 29,521,770	149,139	147,609
Premium on common shares	107,502	99,223
Retained earnings	258,129	245,005

Accumulated other comprehensive income (loss)	669	(1,067)
Total common equity	515,439	490,770
Total capitalization	810,572	762,961
Total	$ 1,343,024	$ 1,258,650

See accompanying notes to consolidated financial statements

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Otter Tail Corporation
Consolidated Statements of Income
(not audited)

	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
	(In thousands, except share and per share amounts)		(In thousands, except share and per share amounts)	
Operating revenues				
Electric	$ 72,052	$ 71,134	$ 232,403	$ 227,062
Nonelectric	230,183	209,408	676,797	591,191
Total operating revenues	302,235	280,542	909,200	818,253
Operating expenses				
Production fuel electric	16,994	15,846	47,496	42,108
Purchased power electric system use	6,499	8,590	43,531	44,990
Electric operation and maintenance expenses	27,212	26,433	80,738	77,889
Cost of goods sold nonelectric (excludes depreciation; included below)	179,868	161,148	521,500	449,905
Other nonelectric expenses	30,211	29,543	92,346	85,097
Depreciation and amortization	13,366	12,552	39,406	37,155
Property taxes electric	2,538	2,260	7,591	7,429
Total operating expenses	276,688	256,372	832,608	744,573
Operating income	25,547	24,170	76,592	73,680
Other income	619	1,060	1,232	2,147
Interest charges	4,927	5,078	14,821	14,622
Income from continuing operations before income taxes	21,239	20,152	63,003	61,205
Income taxes continuing operations	7,907	6,676	23,160	21,737
Net income from continuing operations	13,332	13,476	39,843	39,468
Discontinued operations				
Income from discontinued operations net of taxes of $0; $0; $0 and $28 for the respective periods				26
Net gain on disposition of discontinued operations net of taxes of $0; $0; $0 and $224 for the respective periods				336
Net income from discontinued operations				362
Net income	13,332	13,476	39,843	39,830
Preferred dividend requirements	184	183	552	551

Earnings available for common shares	$ 13,148	$ 13,293	$ 39,291	$ 39,279
Basic earnings per common share:				
Continuing operations (net of preferred dividend requirement)	$ 0.44	$ 0.45	$ 1.33	$ 1.33
Discontinued operations	$	$	$	$ 0.01
	$ 0.44	$ 0.45	$ 1.33	$ 1.34
Diluted earnings per common share:				
Continuing operations (net of preferred dividend requirement)	$ 0.44	$ 0.45	$ 1.31	$ 1.31
Discontinued operations	$	$	$	$ 0.01
	$ 0.44	$ 0.45	$ 1.31	$ 1.32
Average number of common shares outstanding basic	29,745,600	29,412,526	29,644,866	29,377,158
Average number of common shares outstanding diluted	29,995,660	29,805,897	29,887,510	29,764,752
Dividends per common share	$ 0.2925	$ 0.2875	$ 0.8775	$ 0.8625

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, 2007	2006
	(Thousands of dollars)	
Cash flows from operating activities		
Net income	$ 39,843	$ 39,830
Adjustments to reconcile net income to net cash provided by operating activities:		
Net gain from sale of discontinued operations		(336)
Income from discontinued operations		(26)
Depreciation and amortization	39,406	37,155
Deferred investment tax credit	(852)	(860)
Deferred income taxes	2,706	52
Change in deferred debits and other assets	(484)	(564)
Discretionary contribution to pension plan	(4,000)	(4,000)
Change in noncurrent liabilities and deferred credits	6,116	4,552
Allowance for equity (other) funds used during construction		(611)
Change in derivatives net of regulatory deferral	(163)	3,364
Stock compensation expense	1,592	1,871
Other net	(469)	(123)
Cash (used for) provided by current assets and current liabilities:		
Change in receivables	(26,883)	(9,063)
Change in inventories	7,779	(17,663)
Change in other current assets	3,562	(19,260)
Change in payables and other current liabilities	(15,194)	12,248
Change in interest and income taxes payable	4,382	(3,831)
Net cash provided by continuing operations	57,341	42,735
Net cash provided by discontinued operations		1,011
Net cash provided by operating activities	57,341	43,746
Cash flows from investing activities		
Capital expenditures	(99,433)	(53,291)
Proceeds from disposal of noncurrent assets	8,297	3,623
Acquisitions net of cash acquired	(6,750)	
Increases in other investments	(5,824)	(3,540)
Net cash used in investing activities continuing operations	(103,710)	(53,208)
Net proceeds from the sales of discontinued operations		1,898
Net cash used in investing activities	(103,710)	(51,310)
Cash flows from financing activities		

Change in checks written in excess of cash				(11)
Net short-term borrowings		39,881		38,037
Proceeds from issuance of common stock, net of issuance expenses		7,633		1,634
Payments for retirement of common stock		(305)		(463)
Proceeds from issuance of long-term debt		25,128		142
Debt issuance expenses		(328)		(302)
Payments for retirement of long-term debt		(2,445)		(2,523)
Dividends paid		(26,601)		(25,954)
Net cash provided by financing activities continuing operations		42,963		10,560
Net cash provided by financing activities discontinued operations				
Net cash provided by financing activities		42,963		10,560
Effect of foreign exchange rate fluctuations on cash		(2,681)		(427)
Net change in cash and cash equivalents		(6,087)		2,569
Cash and cash equivalents at beginning of period continuing operations		6,791		5,430
Cash and cash equivalents at end of period continuing operations	$	704	$	7,999
Supplemental cash flow information				
Cash paid during the year from continuing operations for:				
Interest (net of amount capitalized)	$	11,899	$	11,419
Income taxes	$	18,896	$	28,967
Cash paid during the year from discontinued operations for:				
Interest	$		$	91
Income taxes	$		$	423

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, 2006, 2005 and 2004 included in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2006. Because of seasonal and other factors, the earnings for the three-month and nine-month periods ended September 30, 2007 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, 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, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

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

Some of the operating businesses enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. In the first nine months of 2007, 29.5% of the Company s revenues were recorded under the percentage-of-completion method. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company s wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized. The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	September 30, 2007	December 31, 2006
Costs incurred on uncompleted contracts	$ 311,917	$ 257,370
Less billings to date	(338,756)	(284,273)
Plus estimated earnings recognized	54,569	35,955
	$ 27,730	$ 9,052

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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, 2007	December 31, 2006
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 44,055	$ 38,384
Billings in excess of costs and estimated earnings on uncompleted contracts	(16,325)	(29,332)
	$ 27,730	$ 9,052

Inventories

Inventories consist of the following:

(in thousands)	September 30, 2007	December 31, 2006
Finished goods	$ 40,789	$ 46,477
Work in process	6,203	5,663
Raw material, fuel and supplies	50,765	50,862
	$ 97,757	$ 103,002

Goodwill and Other Intangible Assets

Goodwill increased $1,132,000 in the first nine months of 2007, primarily as a result of the acquisition of Pro Engineering, LLC (Pro Engineering) by BTD Manufacturing, Inc. (BTD) in May 2007.

The following table summarizes the components of the Company s intangible assets at September 30, 2007 and December 31, 2006:

	September 30, 2007			December 31, 2006		
(in thousands)	Gross Carrying amount	Accumulated amortization	Net carrying amount	Gross Carrying amount	Accumulated amortization	Net carrying amount
Amortized intangible assets:						
Covenants not to compete	$ 2,637	$ 2,045	$ 592	$ 2,198	$ 1,813	$ 385
Customer relationships	10,879	1,358	9,521	10,574	1,016	9,558
Other intangible assets including contracts	2,787	1,714	1,073	2,083	1,291	792
Total	$ 16,303	$ 5,117	$ 11,186	$ 14,855	$ 4,120	$ 10,735
Non-amortized intangible assets:						
Brand/trade name	$ 9,512	$	$ 9,512	$ 9,345	$	$ 9,345

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 $985,000 for the nine months ended September 30, 2007 compared to $829,000 for the nine months ended September 30, 2006. The estimated annual amortization expense for these intangible assets for the next five years is $1,238,000 for 2007, $889,000 for 2008, $795,000 for 2009, $621,000 for 2010 and $516,000 for 2011.

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Comprehensive Income

(in thousands)	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
Net income	$ 13,332	$ 13,476	$ 39,843	$ 39,830
Other comprehensive income (loss) (net-of-tax)				
Foreign currency translation gain (loss)	571	(19)	1,617	545
Amortization of unrecognized losses and costs related to postretirement benefit programs	43		131	
Unrealized (loss) on cash flow hedges		(271)		(271)
Unrealized gain (loss) on available-for-sale securities	5	45	(12)	33
Total other comprehensive income (loss)	619	(245)	1,736	307
Total comprehensive income	$ 13,951	$ 13,231	$ 41,579	$ 40,137

New Accounting Standards

FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109,* was issued by the Financial Accounting Standards Board (FASB) in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes*. The Company adopted FIN No. 48 on January 1, 2007 and has recognized, in its consolidated financial statements, the tax effects of all tax positions that are more-likely-than-not to be sustained on audit based solely on the technical merits of those positions as of September 30, 2007. 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. Only tax positions that meet the more-likely-than-not threshold on the reporting date may be recognized. The cumulative effect of adoption of FIN No. 48, which is reported as an adjustment to the beginning balance of retained earnings, was $119,000. As of the date of adoption, the total amount of unrecognized tax benefits for uncertain tax positions was $1,874,000. The amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate was $575,000 as of January 1, 2007. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes.

The balance of unrecognized tax benefits of $1,874,000 on the date of adoption of FIN No. 48 was reduced by $1,566,000 in September 2007 as a result of the Company s 2003 U.S. federal and North Dakota tax returns being closed to examination or audit. The adjustment of $1,566,000 resulted in a decrease of $377,000 to income tax expense and an increase of $1,189,000 to deferred taxes payable. The total amount of unrecognized tax benefits as of September 30, 2007 is $506,000, which is not expected to change significantly within the next 12 months.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of September 30, 2007 the Company is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2004. As of September 30, 2007 the Company s earliest open tax year in which an audit can be initiated by state taxing authorities in the Company s major operating jurisdictions is 2003 for Minnesota and 2004 for North Dakota.

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 is evaluating the impact that adoption of SFAS No. 157 could have on its consolidated financial statements.

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SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115,* was issued by the FASB in February 2007. SFAS No. 159, provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The Company is evaluating the impact that adoption of SFAS No. 159 could have on its consolidated financial statements.

Acquisitions

On February 19, 2007 ShoreMaster, Inc. (ShoreMaster) acquired the assets of the Aviva Sports product line for $2.0 million in cash. The Aviva Sports product line will be operated through Aviva Sports, Inc. (Aviva), a newly-formed wholly owned subsidiary of ShoreMaster. The Aviva Sports product line is sold internationally and consists of products for consumer use in the pool, lake and yard, as well as commercial use at summer camps, resorts and large public swimming pools. The acquisition of the Aviva Sports product line fits well with the other product lines of ShoreMaster, a leading manufacturer and supplier of waterfront equipment.

On May 15, 2007 BTD acquired the assets of Pro Engineering for $4.8 million in cash. Pro Engineering specializes in providing metal parts stampings to customers in the Midwest. The acquisition of Pro Engineering by BTD provides expanded growth opportunities for both companies.

Disclosure of pro forma information related to the results of operations of the acquired entities for the periods presented in this report is not required due to immateriality.

Below, are condensed balance sheets, at the dates of the respective business combinations, disclosing the preliminary allocation of the purchase price assigned to each major asset and liability category of Aviva and Pro Engineering:

(in thousands)	Aviva	Pro Engineering
Assets		
Current assets	$ 2,083	$ 1,956
Goodwill		1,048
Other intangible assets	870	396
Fixed assets		1,600
Total assets	$ 2,953	$ 5,000
Liabilities		
Current liabilities	$ 988	$ 215
Noncurrent liabilities		
Total liabilities	$ 988	$ 215
Cash paid	$ 1,965	$ 4,785

Other intangible assets related to the Aviva acquisition include $83,000 for a nonamortizable brand name and $787,000 in intangible assets being amortized over various periods up to 15 years. Other intangible assets related to the Pro Engineering acquisition include $51,000 for a nonamortizable brand name and $345,000 in intangible assets being amortized over various periods up to 20 years.

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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. In addition, the electric utility is an active wholesale participant in the Midwest Independent Transmission System Operator (MISO) markets. The electric utility operations have been the Company s primary business since incorporation. The Company s electric operations, including wholesale power sales, are operated as a division of Otter Tail Corporation.

All of the businesses in the following segments are owned by a wholly owned subsidiary of the Company.

Plastics consists 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 have manufacturing facilities in Minnesota, North Dakota, South Carolina, Missouri, California, Florida and Ontario, Canada and sell products primarily in the United States.

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

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

Other business operations consists of businesses in residential, commercial and industrial electric contracting industries, fiber optic and electric distribution systems, wastewater and HVAC systems construction, transportation and energy services, as well as 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 6 Canadian provinces.

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.

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

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
United States of America	97.8%	96.8%	96.7%	97.0%
Canada	0.9%	1.4%	1.4%	1.5%
All other countries (none greater than 1%)	1.3%	1.8%	1.9%	1.5%

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The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information on continuing operations for the business segments for three and nine months ended September 30, 2007 and 2006 and total assets by business segment as of September 30, 2007 and December 31, 2006 are presented in the following tables:

Operating Revenue

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2007	2006	2007	2006
Electric	$ 72,110	$ 71,206	$ 232,662	$ 227,308
Plastics	36,975	45,941	114,319	136,731
Manufacturing	95,330	76,667	286,341	226,555
Health services	31,360	35,432	96,775	100,341
Food ingredient processing	15,714	11,474	53,612	30,635
Other business operations	51,956	40,739	129,012	99,397
Intersegment eliminations	(1,210)	(917)	(3,521)	(2,714)
Total	$ 302,235	$ 280,542	$ 909,200	$ 818,253

Interest Expense

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2007	2006	2007	2006
Electric	$ 2,465	$ 2,561	$ 7,356	$ 7,691
Plastics	242	166	750	642
Manufacturing	2,141	1,799	6,125	5,011
Health services	223	225	683	695
Food ingredient processing	34	157	167	354
Other business operations	5,074	4,920	15,009	14,236
Intersegment eliminations	(5,252)	(4,750)	(15,269)	(14,007)
Total	$ 4,927	$ 5,078	$ 14,821	$ 14,622

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2007	2006	2007	2006
Electric	$ 3,595	$ 3,488	$ 9,500	$ 10,473
Plastics	940	3,067	5,081	9,273
Manufacturing	2,359	1,690	7,564	5,988
Health services	84	243	1,306	903
Food ingredient processing	942	(690)	1,891	(1,652)
Other business operations	(13)	(1,122)	(2,182)	(3,248)

Total	$ 7,907	$ 6,676	$ 23,160	$ 21,737

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Earnings Available for Common Shares from Continuing Operations

(in thousands)	Three months ended September 30, 2007	2006	Nine months ended September 30, 2007	2006
Electric	$ 6,309	$ 6,311	$ 16,939	$ 18,934
Plastics	1,384	4,578	7,610	14,177
Manufacturing	3,477	2,456	11,351	8,861
Health services	53	300	1,709	1,141
Food ingredient processing	993	(1,078)	2,985	(3,504)
Other business operations*	932	726	(1,303)	(692)
Total	$ 13,148	$ 13,293	$ 39,291	$ 38,917

* Other business operations includes corporate general and administrative expenses net-of-tax of $1,270,000 and $1,680,000 for the three months ended September 30, 2007 and 2006, respectively, and $5,633,000 and $5,479,000 for the nine months ended September 30, 2007 and 2006, respectively.

Total Assets

(in thousands)	September 30, 2007	December 31, 2006
Electric	$ 727,959	$ 689,653
Plastics	80,491	80,666
Manufacturing	260,569	219,336
Health services	63,635	66,126
Food ingredient processing	94,149	94,462

Other business operations	116,221	108,118
Discontinued operations		289
Total	$ 1,343,024	$ 1,258,650

Rate and Regulatory Matters

Minnesota AAA Fuel Clause Filing   In a 2005 Fuel Clause Adjustment (FCA) docket that remains open, the Minnesota Department of Commerce (MNDOC) requested that the Minnesota Public Utilities Commission (MPUC) order Otter Tail Power Company to refund 75% of its 2006 asset-based wholesale margins through the FCA in 2007. The Residential and Small Business Utilities Division of the Minnesota Office of Attorney General (MN RUD-OAG) also filed a request with the MPUC agreeing with the MNDOC that there should be a sharing of wholesale margins with ratepayers, but instead of limiting the sharing to 75% of asset-based margins, the MN RUD-OAG recommended that 100% of asset-based wholesale margins, 25% of non-asset-based wholesale margins and 80% of margins from the sale of wholesale ancillary services should be credited to retail customers through the Otter Tail Power Company s fuel clause adjustment. The MPUC has not ruled on the MNDOC and MN RUD-OAG requests but has deferred consideration of the matter to the pending Annual Automatic Adjustment Report docket. The MNDOC also raised significant related issues in the FCA docket, including an assertion that Otter Tail Power Company and other Minnesota utilities have not appropriately allocated MISO costs between asset-based and non-asset-based transactions. The MNDOC and Otter Tail Power Company have identified two operational situations which are not covered in the approved method for allocating MISO costs. One relates to plants not expected to be available for retail but that produce energy in certain hours, resulting in wholesale sales. The other situation is the sale of Financial Transmission Rights (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007, Otter Tail Power Company determined its Minnesota customers   portion of costs associated with these situations to be $765,000. The data has been provided to the MNDOC. Otter Tail Power Company offered to

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refund $765,000 to its Minnesota customers to settle the issues raised by the MNDOC, and the MNDOC accepted the offer in October 2007. However, the agreement has not been approved by the MPUC.

2007 Minnesota General Rate Case Filing Otter Tail Power Company filed a general rate case in Minnesota on October 1, 2007 requesting an interim rate increase of 5.41% effective November 30, 2007 and a final overall rate increase of 6.66%. If approved by the MPUC, interim rates will remain in effect for all Minnesota customers until the MPUC makes a final determination on the request, which is expected by August 1, 2008. If final rates are lower than interim rates, Otter Tail Power Company will refund Minnesota customers the difference with interest.

Capacity Expansion 2020 (CapX) Mega Certificate of Need On August 16, 2007 the eleven CapX utilities asked the MPUC to determine the need for three 345-kilovolt transmission lines. These lines would help ensure continued reliable electricity service in Minnesota and the surrounding region by upgrading and expanding the high-voltage transmission network and providing capacity for more wind energy resources to be developed in southern and western Minnesota, eastern North Dakota and South Dakota. The proposed lines would span more than 600 miles and represent one of the largest single transmission initiatives in the region in several years. The MPUC is expected to decide if the lines are needed by early 2009. The MPUC would determine routes for the new lines in separate proceedings. Portions of the lines would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are complete (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading the project, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. The Company s 2007 - 2011 capital budget included $59 million for CapX expenditures.

North Dakota Fuel Clause/MISO Schedule 16 and 17 Agreement In August 2007 the North Dakota Public Service Commission (NDPSC) approved a settlement agreement between Otter Tail Power Company and an intervener representing several large industrial customers in North Dakota. When the MISO Day 2 energy market began in April 2005, the characterization of some of Otter Tail Power Company s energy costs changed, though the essential nature of those costs did not. Fuel and purchased energy costs incurred to serve retail customers are recoverable through the FCA in North Dakota. Under the approved settlement agreement, Otter Tail Power Company will refund to North Dakota customers the schedule 16 and 17 costs collected through the FCA since April 2005. Otter Tail Power Company can defer recognition of these costs and request recovery of them in its next general rate case. Purchase power system use expense was reduced and an offsetting regulatory asset was established for the amount of the refund. The refund amount of $540,000 will be credited to North Dakota customers through the FCA beginning in October 2007. Also as part of the settlement, Otter Tail Power Company agreed to file a general rate case in North Dakota between November 1 and December 31, 2008.

Big Stone II Project Otter Tail Power Company s integrated resource plan (IRP) includes generation from Big Stone II, a proposed coal-fired base-load generation unit, beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. Approval of this IRP is pending with the MPUC, along with a Certificate of Need for transmission lines located in Minnesota that are required for interconnection of the Big Stone II project to the transmission grid. Additionally, a filing in North Dakota for an advanced determination of prudence of Big Stone II was made in November 2006. In September 2007, two project participants, Great River Energy and Southern Minnesota Municipal Power Agency, announced their intention to withdraw from the project. The five remaining project participants are currently assessing options for downsizing the plant or adding new participants. New procedural schedules are being established in the various project-related proceedings, which will take into consideration the optimal plant configuration decided on by the remaining participants.

In February 2007 the South Dakota Appeals Court issued an opinion affirming the decision of the South Dakota Public Utilities Commission to grant a siting permit for Big Stone II. The permit has now been appealed to the South Dakota Supreme Court, which is expected to hear the appeal during its fall session.

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As of September 30, 2007 Otter Tail Power Company had capitalized $8.1 million in costs related to the planned construction of Big Stone II. 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 may be subject to expense and may not be recoverable.

Federal

On April 25, 2006 the Federal Energy Regulatory Commission (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 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 of the April 25, 2006 order, 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 that virtual supply offers cause within 60 days of the October 26, 2006 order. On December 27, 2006 the FERC issued an order granting rehearing of the October 26, 2006 order.

On March 15, 2007 the FERC issued an order denying requests for rehearing of the RSG rehearing order dated October 27, 2006. In the March 15, 2007 order on rehearing, the FERC stated that its findings in the April 25, 2006 RSG order that virtual offers should share in the allocation of RSG costs, per the terms of the currently-effective tariff, served as notice to market participants that virtual offers, for those market participants withdrawing energy, were liable for RSG charges. FERC clarified that the RSG rehearing order s waiver of refunds applies to the period before that order, from market start-up in April 2005 until April 24, 2006. After that date, virtual supply offers are liable for RSG costs and therefore, to the extent virtual supply offers were not assessed RSG costs, refunds are due for the period starting April 25, 2006.

On November 5, 2007, the FERC issued two orders related to the RSG proceeding. In the first order, the FERC accepted the Midwest ISO s April 17, 2007 RSG Compliance filing to comply with the Commission s March 15, 2007 RSG Order. The compliance reinserted language requiring the actual withdrawal of energy by market participants, restored the Midwest ISO s original TEMT language allocating RSG costs to virtual transactions, revised the effective date for allocation to imports, provided an explanation of its efforts to reflect partial-hour revenue determinations in its software development, and revised several definitions.

The second related RSG order issued by FERC on November 5, 2007 was its Order on Rehearing on FERC s April 25, 2006 Order in which it rejected the Midwest ISO s proposal to remove references to virtual supply from the TEMT provisions related to calculating RSG charges (FERC Docket Nos. ER04-691-084 and ER04-691-086). In this order, the FERC denied the requests for rehearing of the RSG Second Rehearing Order (Otter Tail Power Company was one of the parties that sought rehearing) and FERC denied all requests for rehearing of the RSG Compliance Order.

In the RSG Compliance Order, the Commission rejected the Midwest ISO s proposal to allocate costs based on net virtual offers, i.e., virtual offers minus virtual bids, and clarified that the currently-effective tariff, which allocates RSG costs to virtual supply offers, remains in effect.

In the RSG Second Rehearing Order, the Commission clarified that for those market participants withdrawing energy, to the extent virtual supply offers were not assessed RSG costs, refunds were due for the period starting April 25, 2006.

The Company recorded a $1.7 million ($1.0 million net-of-tax) charge to earnings in the first quarter of 2007 based on an internal estimate of the net impact of MISO reallocating RSG charges in response to the FERC order on rehearing. In May 2007, MISO informed affected market participants of the impact of reallocating charges based on its interpretation of the FERC order on rehearing. Based on MISO s interpretation of the order on rehearing, the Company estimated the reallocation of charges would not have a significant impact on earnings previously recognized by the Company. Accordingly, the Company revised its first quarter estimated charge of $1.7 million ($1.0 million net-of-tax) to zero in the second quarter of 2007. The Company is awaiting MISO s response to the November 5, 2007 RSG compliance Order and cannot determine, as of the date of this report on Form 10-Q, what financial impact, if any, the order will have on the Company s 2007 consolidated results of operations.

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, 2007	December 31, 2006
Regulatory assets:		
Unrecognized transition obligation, prior service costs and actuarial losses on pension and other postretirement benefits	$ 34,187	$ 36,736
Deferred income taxes	10,170	11,712
Accrued cost-of-energy revenue	3,592	10,735
Reacquisition premiums	2,470	2,694
MISO schedule 16 and 17 deferred administrative costs MN	781	541
MISO schedule 16 and 17 deferred administrative costs ND	523	
Deferred marked-to-market losses	451	
Deferred conservation program costs	331	1,036
Accumulated ARO accretion/depreciation adjustment	321	249
Plant acquisition costs	118	151
Total regulatory assets	$ 52,944	$ 63,854
Regulatory liabilities:		
Accumulated reserve for estimated removal costs	$ 59,784	$ 58,496
Deferred income taxes	4,684	5,228
Gain on sale of division office building	146	151
Total regulatory liabilities	$ 64,614	$ 63,875
Net regulatory (liability) position	$ (11,670)	$ (21)

The regulatory asset related to the unrecognized transition obligation on postretirement medical benefits and prior service costs and actuarial losses on pension and other postretirement benefits represents benefit costs that will be subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. The regulatory assets and liabilities related to deferred income taxes result from changes in

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statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes*. Accrued cost-of-energy revenue included in Accrued utility revenues will be recovered over the next nine months. 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 14.8 years. MISO schedule 16 and 17 deferred administrative costs were excluded from recovery through the FCA in Minnesota in a December 2006 order issued by the MPUC. The MPUC ordered the Company to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the Company s Minnesota general rate case filed on October 1, 2007. MISO schedule 16 and 17 deferred administrative costs were excluded from recovery through the FCA in North Dakota in an August 2007 order issued by the NDPSC. The NDPSC ordered the Company to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the Company s next general rate case in North Dakota scheduled to be filed in November or December of 2008. All deferred marked-to-market losses are related to forward purchases of energy scheduled for delivery in November 2007. Deferred conservation program costs represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. The accumulated reserve for estimated removal costs is reduced for actual removal costs incurred. Plant acquisition costs will be amortized over the next 2.7 years. 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.

Common Shares and Earnings per Share

Following is a reconciliation of the Company s common shares outstanding from December 31, 2006 through September 30, 2007:

Common shares outstanding, December 31, 2006	29,521,770
Issuances:	
Stock options exercised	293,382
Directors compensation:	
Restricted shares	15,200
Unrestricted shares	885
Vesting of restricted stock units	4,522
Restricted shares issued for employee compensation	600
Retirements:	
Shares withheld for individual income tax requirements	(8,409)
Restricted shares forfeited	(80)
Common shares outstanding, September 30, 2007	29,827,870

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

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restricted stock units granted to employees are considered dilutive for the purpose of calculating diluted earnings per share. Shares expected to be awarded for stock performance awards granted to executive officers are considered dilutive for the purpose of calculating diluted earnings per share.

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the three and nine month periods ended September 30, 2007 and 2006:

Three months ended September 30,	Options Outstanding	Range of Exercise Prices
2007		N/A
2006	213,000	\$29.74 - \$31.34

Nine months ended September 30,	Options Outstanding	Range of Exercise Prices
2007		N/A
2006	213,000	\$29.74 - \$31.34

Share-based Payments

On April 9, 2007 the Compensation Committee of the Company s Board of Directors granted 23,450 restricted stock units to key employees under the 1999 Stock Incentive Plan, as amended (Incentive Plan), payable in common shares on April 8, 2011, the date the units vest. The grant date fair value of each restricted stock unit was \$30.07 per share, as determined under a Monte Carlo valuation method.

On April 9, 2007 the Compensation Committee of the Company s Board of Directors granted 15,200 shares of restricted stock to the Company s nonemployee directors under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2008 through 2011. The grant date fair value of each share of restricted stock was \$35.045 per share, the average market price on the date of grant.

The Company has six share-based payment programs. As of September 30, 2007 the total remaining unrecognized compensation expense related to share-based compensation was approximately \$2.8 million (before income taxes), which will be amortized over a weighted-average period of 2.3 years.

Amounts of compensation expense recognized under the Company s six share-based payment programs for the three and nine months ended September 30, 2007 and 2006 are presented in the table below:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2007	2006	2007	2006
1999 Employee Stock Purchase Plan	\$ 66	\$ 54	\$ 193	\$ 174
Stock options granted under the Incentive Plan		68	90	204
Restricted stock granted to directors	103	80	350	321
Restricted stock granted to employees	43	183	455	625
Restricted stock units granted to employees	103	69	281	358
Stock performance awards granted to executive officers	221	267	662	802
Totals	\$ 536	\$ 721	\$ 2,031	\$ 2,484

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Short-term and Long-term Borrowings

Short-term Debt At September 30, 2007, the Company had outstanding a $150 million line of credit pursuant to a Credit Agreement dated as of April 26, 2007 among the Company, 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 (the Company Credit Agreement). As of September 30, 2007, $68.0 million of the line of credit was in use and $15.7 million was restricted from use to cover outstanding letters of credit. The Company Credit Agreement was scheduled to expire on April 26, 2009 but was terminated and replaced by a new credit agreement entered into by Varistar Corporation on October 2, 2007, as described under Subsequent Events.

On September 1, 2006 Otter Tail Corporation, dba Otter Tail Power Company and U.S. Bank National Association entered into a Credit Agreement (the Otter Tail Power Company Credit Agreement) providing for a separate $25 million line of credit. This line of credit is an unsecured revolving credit facility that Otter Tail Power Company can draw on to support the working capital needs and other capital requirements of its electric operations. Borrowings under this 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 Otter Tail Power Company Credit Agreement contains a number of restrictions on the business of Otter Tail Power Company, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Otter Tail Power Company Credit Agreement also contains certain financial covenants. Specifically, the Company must not permit its debt-to-total capitalization ratio to exceed 60% or permit its interest and dividend coverage ratio to be less than 1.5 to 1.

On April 13, 2007 the parties to the Otter Tail Power Company Credit Agreement entered into a First Amendment to Credit Agreement which increased the commitment from $25 million to $50 million. On August 31, 2007 the parties entered into a Second Amendment to the Credit Agreement which further increased the commitment from $50 million to $75 million, and which extended the termination date from September 1, 2007 to September 1, 2008. As of September 30, 2007, $10.8 million was borrowed under the Otter Tail Power Company Credit Agreement.

Long-term Debt In February 2007 the Company entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which the Company agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of the Company s senior notes due November 30, 2017. Cascade owned approximately 8.7% of the Company s outstanding common stock as of June 30, 2007. The notes will bear interest at a rate of 5.778% per annum, subject to adjustment in the event certain ratings assigned to the Company s long-term senior unsecured indebtedness are downgraded below specific levels prior to the closing of the note purchase. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of the Company s $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The closing is expected to occur on December 3, 2007 subject to the satisfaction of certain conditions to closing, including: (i) no event or events will have occurred since December 31, 2005 that have had or would reasonably be expected to have a material adverse effect on the Company and its subsidiaries taken as a whole; (ii) certain senior executives will remain in their current positions; (iii) there is no change in control or impermissible sale of assets; (iv) the ratio of the Company s consolidated debt to earnings before interest, taxes, depreciation and amortization as of September 30, 2007 will be less than 3.5 to 1; (v) certain waivers will have been obtained; and (vi) certain other customary conditions of closing will have been satisfied. The proceeds of this financing will be used to redeem the Company s $50 million 6.375% Senior Debentures due December 1, 2007.

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At closings completed in August 2007 and October 2007, the Company issued $155 million aggregate principal amount of its senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007 between the Company and these purchasers. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes, were issued and sold by the Company at a second closing on October 1, 2007.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, and the 2001 Note Purchase Agreement states the Company may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreement. The 2007 Note Purchase Agreement states the Company must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of the Company.

The 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement contain a number of restrictions on the businesses of the Company and its subsidiaries, and the Cascade Note Purchase Agreement contains similar restrictions that will be effective upon issuance to Cascade of the notes thereunder. In each case these include restrictions on the ability of the Company and certain of its subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements and the Lombard US Equipment Finance loan agreement also contain covenants by the Company not to permit its debt-to-total capitalization ratio to exceed 60% or permit its interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, its interest charges coverage ratio) to be less than 1.5 to 1, determined as of the end of a fiscal quarter for the preceding twelve-month period. The note purchase agreements further restrict the Company from allowing its priority debt to exceed 20% of total capitalization. The Company was in compliance with all of the covenants under its financing agreements as of September 30, 2007.

The Company s obligations under the 2001 Note Purchase Agreement are, and its obligations under the Cascade Note Purchase Agreement will be, guaranteed by certain of the Company s subsidiaries.

Class B Stock Options of Subsidiary

As of September 30, 2007 there were 958 options for the purchase of IPH Class B common shares outstanding with a combined exercise price of $743,000, of which 200 options were in-the-money with a combined exercise price of $30,000. In April 2007, 100 options were forfeited as a result of a voluntary termination.

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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, 2007	2006	Nine months ended September 30, 2007	2006
Service cost benefit earned during the period	$ 1,102	$ 1,373	$ 3,628	$ 3,793
Interest cost on projected benefit obligation	2,626	2,738	8,092	7,826
Expected return on assets	(3,265)	(3,086)	(9,711)	(9,216)
Amortization of prior-service cost	187	185	557	557
Amortization of net actuarial loss	200	627	818	1,383
Net periodic pension cost	$ 850	$ 1,837	$ 3,384	$ 4,343

The Company made $4.0 million in discretionary contributions to its pension plan in the nine months ended September 30, 2007.

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, 2007	2006	Nine months ended September 30, 2007	2006
Service cost benefit earned during the period	$ 157	$ 107	$ 470	$ 320
Interest cost on projected benefit obligation	362	325	1,087	977
Amortization of prior-service cost	17	18	51	53
Recognized net actuarial loss	135	118	405	354
Net periodic pension cost	$ 671	$ 568	$ 2,013	$ 1,704

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, 2007	2006	Nine months ended September 30, 2007	2006
Service cost benefit earned during the period	$ 194	$ 321	$ 824	$ 989
Interest cost on projected benefit obligation	528	643	1,924	1,917
Amortization of transition obligation	187	187	561	561
Amortization of prior-service cost	(52)	(77)	(155)	(229)
Amortization of net actuarial loss	(125)	151	133	417
Effect of Medicare Part D expected subsidy	(105)	(571)	(925)	(1,157)
Net periodic postretirement benefit cost	$ 627	$ 654	$ 2,362	$ 2,498

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Discontinued Operations

In June 2006 OTESCO, the Company s energy services company, sold its natural gas marketing operations for $0.5 million in cash. SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* requires that OTESCO s natural gas marketing operations be classified and reported separately as discontinued operations. The results of discontinued operations for the nine months ended September 30, 2006 are summarized as follows:

(in thousands)	Nine months ended September 30, 2006
Operating revenues	$ 28,234
Income before income taxes	54
Gain on Disposition pretax	560
Income tax expense	252

At December 31, 2006 the major components of assets and liabilities of discontinued operations at estimated fair market values consisted of deferred taxes of $289,000 and warranty reserves of $197,000 from St. George Steel Fabrication, Inc., which was sold in 2005. These assets and liabilities were disposed of or settled in the second quarter of 2007.

Subsequent Events

On October 1, 2007 the second and final closing under the 2007 Note Purchase Agreement was completed. The Company issued and sold the remaining $30 million aggregate principal amount of its Series C Notes, $37 million aggregate principal amount of its Series D Notes, $33 million aggregate principal amount of its Series A Notes and $30 million aggregate principal amount of its Series B Notes. On October 15, 2007 a portion of the proceeds from the issuance were used to retire $40 million aggregate principal amount of the Company s 5.625% Series of Insured Senior Notes due October 1, 2017 and $25 million aggregate principal amount of the Company s 6.80% Series of Senior Notes due October 1, 2032.

On October 2, 2007 Varistar Corporation (Varistar), a wholly-owned subsidiary of the Company, entered into a $200 million Credit Agreement (the Varistar Credit Agreement) with the following banks: U.S. Bank National Association as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. The Varistar Credit Agreement is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Varistar Credit Agreement expires on October 2, 2010. Borrowings under the line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on Varistar s adjusted cash flow leverage ratio (as defined in the Varistar Credit Agreement). The Varistar Credit Agreement replaces the Company s Credit Agreement. The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties. The Varistar Credit Agreement also contains certain financial covenants. Specifically, Varistar must maintain a fixed charge coverage ratio of not less than 1.25 to 1.00 and must not permit its cash flow leverage ratio to exceed 3.00 to 1.00. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company s credit ratings. Varistar s obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Outstanding letters of credit issued by Varistar can reduce the amount available for borrowing under the line by up to $30 million.

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On October 29, 2007 the Company s Board of Directors granted performance share awards to the Company s executive officers under the Incentive Plan. Under these awards, the Company s executive officers could earn up to an aggregate of 109,000 common shares based on the Company s total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance period of January 1, 2007 through December 31, 2009. The aggregate target share award is 54,500 shares. Actual payment may range from zero to 200 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. In accordance with SFAS No. 123(R), the Company will estimate the fair value of the common shares projected to be awarded on the date of grant under a Monte Carlo valuation method and record compensation expense over the remaining performance period.

Also on October 29, 2007 the Company s Board of Directors granted 16,700 shares of restricted stock to the Company s executive officers under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2008 through 2011 and are eligible for full dividend and voting rights. The grant-date fair value of the restricted shares is $35.84 per share, the average market price of the shares on their grant date. The $599,000 fair value of the restricted shares awarded will be recorded as compensation expense over the vesting period.

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

RESULTS OF OPERATIONS

Comparison of the Three Months Ended September 30, 2007 and 2006

Consolidated operating revenues were $302.2 million for the three months ended September 30, 2007 compared with $280.5 million for the three months ended September 30, 2006. Operating income was $25.5 million for the three months ended September 30, 2007 compared with $24.2 million for the three months ended September 30, 2006. The Company recorded diluted earnings per share of $0.44 for the three months ended September 30, 2007 compared to $0.45 for the three months ended September 30, 2006.

Following is a more detailed analysis of our operating results by business segment for the three and nine month periods ended September 30, 2007 and 2006, followed by our outlook for the remainder of 2007 and a discussion of changes in our consolidated financial position during the nine months ended September 30, 2007.

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, 2007 and 2006 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, 2007	Three months ended September 30, 2006
Operating revenues:		
Electric	$ 59	$ 72
Nonelectric	1,151	845
Cost of goods sold	417	359
Other nonelectric expenses	793	558

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Electric

(in thousands)	Three months ended September 30, 2007	2006	Change	% Change
Retail sales revenues	$ 59,896	$ 59,694	$ 202	0.3
Wholesale revenues	6,779	6,099	680	11.1
Net marked-to-market loss	(751)	(207)	(544)	(262.8)
Other revenues	6,186	5,620	566	10.1
Total operating revenues	$ 72,110	$ 71,206	$ 904	1.3
Production fuel	16,994	15,846	1,148	7.2
Purchased power system use	6,499	8,590	(2,091)	(24.3)
Other operation and maintenance expenses	27,212	26,433	779	2.9
Depreciation and amortization	6,581	6,430	151	2.3
Property taxes	2,538	2,260	278	12.3
Operating income	$ 12,286	$ 11,647	$ 639	5.5

Retail electric revenues increased $0.2 million, reflecting a $0.5 million increase in revenue before Fuel Clause Adjustment (FCA) revenues related to a 4.1% increase in retail megawatt-hour (mwh) sales, offset by a $0.3 million decrease in FCA revenues related to a 6.6% decrease in fuel and purchased power costs per mwh generated and purchased for system use. Commercial mwh sales increased 3.7% between the quarters mainly due to increased consumption by ethanol producers. Industrial mwh sales increased 15.0% between the quarters mainly due to increased consumption by pipeline customers. Weather did not have a discernable impact on the increase in retail mwh sales between the quarters.

Wholesale electric revenues from company-owned generation were $5.7 million for the quarter ended September 30, 2007 compared with $6.1 million for the quarter ended September 30, 2006. The decrease in wholesale revenues from company-owned generation resulted from an 8.4% decrease in wholesale mwh sales as more company-owned generation was used to serve retail load in the third quarter of 2007 compared with the third quarter of 2006. Net revenues from energy trading activities, including net mark-to-market gains on forward energy contracts, were $0.3 million for the quarter ended September 30, 2007 compared with a $0.2 million net loss for the quarter ended September 30, 2006. The $0.5 million increase in revenue from energy trading activities reflects a $1.1 million increase in profits from purchased power resold and net settlements of forward energy contracts, offset by a $0.5 million increase in net mark-to-market losses on forward energy contracts.

The increase in other electric operating revenues for the three months ended September 30, 2007 compared to the three months ended September 30, 2006 was mainly due to an increase in revenues from contracted work for other companies.

The increase in fuel costs for the three months ended September 30, 2007 compared with the three months ended September 30, 2006 reflects a 6.1% increase in the cost of fuel per mwh generated combined with a 1.1% increase in mwhs generated. Generation used for retail electric sales increased 2.7% while generation for wholesale electric sales decreased 8.4% between the quarters. The increase in the cost of fuel per mwh of generation reflects increases in generation at the electric utility s higher-fuel-cost generation units.

The decrease in purchased power system use (to serve retail customers) is due to a 43.7% decrease in the cost per mwh purchased, partially offset by a 34.4% increase in mwhs purchased. Power purchases in the third quarter of 2007 reflect a lower proportion of purchases indexed to lower natural gas prices than purchases in the third quarter of 2006, resulting in the decrease in cost per mwh purchased between the quarters.

The increase in other operation and maintenance expenses for the three months ended September 30, 2007 compared with the three months ended September 30, 2006 reflects an increase in material costs related to an increase in contracted work completed for other companies between the quarters. The increases in depreciation and amortization expense and property taxes are related to an increase in electric plant in service in 2007 compared with 2006.

Plastics

	Three months ended September 30,			%
(in thousands)	2007	2006	Change	Change
Operating revenues	$ 36,975	$ 45,941	$ (8,966)	(19.5)
Cost of goods sold	31,910	34,172	(2,262)	(6.6)
Operating expenses	1,781	3,284	(1,503)	(45.8)
Depreciation and amortization	769	693	76	11.0
Operating income	$ 2,515	$ 7,792	$ (5,277)	(67.7)

Operating revenues for the plastics segment decreased mainly as result of an 18.9% decrease in the price per pound of pipe sold between the quarters. The decreases in pipe prices and cost of goods sold reflect the effect of an 8.6% decrease in polyvinyl chloride (PVC) resin prices between the quarters. The decrease in plastics segment operating expenses is due to a decrease in sales and employee incentives directly related to the decreases in sales and operating income between the quarters.

Manufacturing

	Three months ended September 30,			%
(in thousands)	2007	2006	Change	Change
Operating revenues	$ 95,330	$ 76,667	$ 18,663	24.3
Cost of goods sold	75,236	61,315	13,921	22.7
Operating expenses	8,800	6,563	2,237	34.1
Depreciation and amortization	3,341	2,845	496	17.4
Operating income	$ 7,953	$ 5,944	$ 2,009	33.8

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

Revenues at DMI Industries, Inc. (DMI) increased $15.0 million as a result of increased production levels and productivity gains at both its West Fargo and Ft. Erie plants. The first phase of a two-phase expansion project at the Ft. Erie plant began operations in April 2007.

Revenues at ShoreMaster, Inc. (ShoreMaster) increased $2.6 million due to increased sales of commercial products. The Aviva Sports product line, acquired by ShoreMaster in February 2007, contributed $0.5 million to the increase in revenues.

Revenues at BTD Manufacturing, Inc. (BTD) increased $0.6 million between the quarters due to $1.5 million in revenues from Pro Engineering, LLC (Pro Engineering), a metal parts stamping business acquired in May 2007, partially offset by a reduction in unit sales at BTD s main manufacturing facility.

Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $0.5 million as a result of increases in product sales volumes between the quarters.

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

Cost of goods sold at DMI increased $12.2 million between the quarters, including $10.3 million in material cost increases. The increase in cost of goods sold is directly related to DMI s increase in production and sales activity at both its West Fargo and Ft. Erie plants.

Cost of goods sold at ShoreMaster increased $1.5 million between the quarters as a result of increases in material and labor costs directly related to the increase in commercial product sales and the acquisition of the Aviva Sports product line in February 2007.

Cost of goods sold at BTD increased $0.5 million between the quarters primarily as a result of increases in subcontractor costs and the acquisition of Pro Engineering in May 2007.

Cost of goods sold at T.O. Plastics decreased $0.1 million between the quarters.

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

Operating expenses at DMI increased $0.9 million as a result of increases in labor and benefit expenses, professional services and sales and promotional expenses including $0.3 million in pre-production start-up costs at DMI s new plant site in Tulsa, Oklahoma, expected to be operational in 2008.

Operating expenses at ShoreMaster increased $0.8 million as a result of increases in professional service expenses, and in labor and sales expenses related to the acquisition of the Aviva Sports product line in February 2007.

Operating expenses at BTD increased $0.5 million between the quarters, reflecting increases in labor and benefit expenses and a $0.1 million gain on the sale of equipment in the third quarter of 2006.

Operating expenses at T.O. Plastics increased by $0.1 million between the quarters.

Depreciation expense increased between the periods mainly as a result of capital additions at all of the manufacturing companies in 2006, but mainly at DMI s Ft. Erie plant.

Health Services

(in thousands)	Three months ended September 30, 2007	2006	Change	% Change
Operating revenues	$ 31,360	$ 35,432	$ (4,072)	(11.5)
Cost of goods sold	24,193	28,100	(3,907)	(13.9)
Operating expenses	5,816	5,686	130	2.3
Depreciation and amortization	1,003	897	106	11.8
Operating income	$ 348	$ 749	$ (401)	(53.5)

Revenues from scanning and other related services decreased $2.2 million as a result of a $1.2 million decrease in revenues from rental and interim installations and a 2.7% decrease in the number of scans performed between the quarters. Revenues from equipment sales and servicing decreased $1.9 million between the quarters as a decrease in traditional dealership distribution of products was mostly offset by increases in manufacturer representative commissions on more manufacturer-direct sales. The decrease in health services revenue was mostly offset by the decrease in health services cost of goods sold due to the decrease in traditional dealership distribution of products. The $0.1 million increase in operating expenses is mainly due to increased sales-related advertising, promotional and travel expenses. The increase in depreciation and amortization expense is due to $4.7 million in capital expenditures in 2006.

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Food Ingredient Processing

(in thousands)	Three months ended September 30, 2007	2006	Change	% Change
Operating revenues	$ 15,714	$ 11,474	$ 4,240	37.0
Cost of goods sold	11,926	11,409	517	4.5
Operating expenses	792	728	64	8.8
Depreciation and amortization	1,017	939	78	8.3
Operating income (loss)	$ 1,979	$ (1,602)	$ 3,581	223.5

The increase in food ingredient processing revenues reflects a 15.0% increase in pounds of product sold combined with a 19.1% increase in the price per pound sold. The increase in revenues was partially offset by a 4.5% increase in cost of goods sold. The cost per pound of product sold decreased 9.1% as a result of decreases in raw potato and natural gas prices between the quarters. Increased sales prices for potato flakes reflect tight supplies in Europe due, in part, to a poor European potato crop in 2006.

Other Business Operations

(in thousands)	Three months ended September 30, 2007	2006	Change	% Change
Operating revenues	$ 51,956	$ 40,739	$ 11,217	27.5
Cost of goods sold	37,021	26,511	10,510	39.6
Operating expenses	13,814	13,840	(26)	(0.2)
Depreciation and amortization	655	748	(93)	(12.4)
Operating income (loss)	$ 466	$ (360)	$ 826	229.4

Corporate general and administrative expenses included in the operating income (loss) from other business operations were $2.1 million and $2.8 million for the three months ended September 30, 2007 and 2006, respectively. Net operating income from other business operations before corporate general and administrative expenses was $2.6 million and $2.4 million for the three months ended September 30, 2007 and 2006, respectively.

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

Revenues at Midwest Construction Services, Inc. (MCS) increased $10.4 million between the quarters as a result of an increase in volume of jobs in progress.

Revenues at Foley Company increased $1.0 million in the third quarter of 2007 compared to the third quarter of 2006 due to an increase in the volume of jobs in progress between the quarters.

Revenues at E.W. Wylie Corporation (Wylie) decreased $0.4 million between the quarters. Revenues from company-operated trucks increased $0.6 million due to a 19.2% increase in miles driven while revenues from owner-operated trucks decreased $0.9 million due to a 19.8% decrease in miles driven. Brokerage revenues decreased $0.1 million.

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

Cost of goods sold at MCS increased $10.0 million due to increases in material, labor and subcontractor costs related to the increase in volume of work performed between the quarters.

Cost of goods sold at Foley Company increased $0.5 million due to labor and benefit cost increases as a result of the increased volume of work performed between the quarters.

Income Taxes Continuing Operations

Income tax expense increased $1.2 million in the three months ended September 30, 2007 compared with the three months ended September 30, 2006 as a result of a $1.1 million increase in income before income taxes between the quarters and a reduction of $0.6 million in income tax liabilities in the third quarter of 2006 related to closed income tax returns. The effective tax rate was 37.2% for the three months ended September 30, 2007 compared with 33.1% for the three months ended September 30, 2006.

Comparison of the Nine Months Ended September 30, 2007 and 2006

Consolidated operating revenues were $909.2 million for the nine months ended September 30, 2007 compared with $818.3 million for the nine months ended September 30, 2006. Operating income was $76.6 million for the nine months ended September 30, 2007 compared with $73.7 million for the nine months ended September 30, 2006. The Company recorded diluted earnings per share from continuing operations of $1.31 for the nine months ended September 30, 2007 compared to $1.31 for the nine months ended September 30, 2006 and total diluted earnings per share from continuing and discontinued operations of $1.31 for the nine months ended September 30, 2007 compared to $1.32 for the nine months ended September 30, 2006. Earnings from discontinued operations for the nine months ended September 30, 2006 included $0.01 per share from a gain on the sale of the natural gas marketing operations of OTESCO, our energy services company, in June 2006.

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, 2007 and 2006 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

(in thousands)	Nine months ended September 30, 2007	Nine months ended September 30, 2006
Operating revenues:		
Electric	$ 259	$ 246
Nonelectric	3,262	2,468
Cost of goods sold	1,173	1,127
Other nonelectric expenses	2,348	1,587

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Electric

(in thousands)	Nine months ended September 30, 2007	2006	Change	% Change
Retail sales revenues	$ 196,573	$ 194,858	$ 1,715	0.9
Wholesale revenues	17,687	18,395	(708)	(3.8)
Net marked-to-market gain	2,647	144	2,503	1,738.2
Other revenues	15,755	13,911	1,844	13.3
Total operating revenues	$ 232,662	$ 227,308	$ 5,354	2.4
Production fuel	47,496	42,108	5,388	12.8
Purchased power system use	43,531	44,990	(1,459)	(3.2)
Other operation and maintenance expenses	80,738	77,889	2,849	3.7
Depreciation and amortization	19,501	19,234	267	1.4
Property taxes	7,591	7,429	162	2.2
Operating income	$ 33,805	$ 35,658	$ (1,853)	(5.2)

The main contributor to the increase in retail revenues was a 3.5% increase in retail mwh sales in the nine months ended September 30, 2007 compared with the nine months ended September 30, 2006, as a result of increased mwh sales to ethanol producers and pipeline customers and a 12.3% increase in heating degree days between the periods. The impact of the 3.5% increase in retail mwh sales on revenues was partially offset by a $3.0 million decrease in FCA revenues between the periods. The decrease in FCA revenues includes decreases in the Minnesota FCA true-up, reduction of an estimated Midwest Independent Transmission System Operator (MISO) refund provision and MISO schedule 16 and 17 refunds totaling $8.1 million, offset by a $5.1 million increase in FCA revenues for recovery of increased fuel and purchased power costs between the periods. See notes to consolidated financial statements for additional information regarding rate and regulatory matters.

Wholesale electric revenues from company-owned generation were $15.2 million for the nine months ended September 30, 2007 compared with $17.9 million for the nine months ended September 30, 2006. The decrease in wholesale revenues from company-owned generation resulted from a 34.9% decrease in wholesale mwh sales as more company-owned generation was used to serve retail load in the first nine months of 2007 compared with the same period in 2006. Advance purchases of electricity in anticipation of coal supply constraints at Big Stone and Hoot Lake plants in the second quarter of 2006 freed up more generation for wholesale sales when coal supplies improved in May 2006. Net revenues from energy trading activities, including net mark-to-market gains on forward energy contracts, were $5.1 million for the nine months ended September 30, 2007 compared with $0.6 million for the nine months ended September 30, 2006. The $4.5 million increase in revenue from energy trading activities reflects a $3.9 million increase in profits from purchased power resold and net settlements of forward energy contracts, a $2.5 million increase in net mark-to-market gains on forward energy contracts and a $0.8 million increase in net profits from virtual transactions, offset by a $2.7 million decrease in profits related to the purchase and sale of financial transmission rights.

The increase in other electric operating revenues for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006 was mainly due to an increase in payments for the use of the electric utility s transmission facilities by other electric utility companies, and an increase in revenues from MISO for transmission and area load control and dispatch services provided by the electric utility.

The increase in fuel costs for the nine months ended September 30, 2007 compared with the nine months ended September 30, 2006 reflects a 4.2% increase in mwhs generated combined with an 8.3% increase in the cost of fuel per mwh generated. Generation used for retail electric sales increased 11.8% while generation for wholesale electric

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sales decreased 34.9% between the periods. The increase in mwhs generated is due to greater plant availability in the first nine months of 2007 compared with the first nine months of 2006. In the second quarter of 2006, Coyote Station was off-line for five weeks of scheduled maintenance and Big Stone Plant experienced a one-week maintenance shutdown. Fuel costs increased $2.1 million at the electric utility s natural gas and fuel oil-fired peaking plants as a result of a 106.6% increase in mwhs generated at those plants. The increase in the cost of fuel per mwh generated was a result of increased generation from the electric utility s higher fuel-cost peaking plants and higher coal costs between the periods.

The decrease in purchased power system use (to serve retail customers) is due to a 13.7% decrease in mwhs purchased for system use, partly offset by a 12.2% increase in the cost per mwh purchased. Advance purchases of electricity in anticipation of coal supply constraints at Big Stone and Hoot Lake plants and the scheduled five-week maintenance shutdown of Coyote Station in the second quarter of 2006 were the reasons for the lower level of mwh purchases for system use in the first nine months of 2007 compared with the first nine months of 2006.

The increase in other operation and maintenance expenses for the nine months ended September 30, 2007 compared with the nine months ended September 30, 2006 includes increases of: (1) $1.8 million in labor and benefit costs related to wage and salary increases averaging approximately 3.8% between the periods, (2) $0.7 million in material costs related to contracted construction work for other companies, (3) $0.5 million in external costs related to rate case preparation, (4) $0.5 million in tree-trimming expenditures, (5) $0.2 million in Big Stone II transmission agreement expenses and (6) $0.2 million in charitable donations. These increases were partially offset by a $1.1 million reduction in material and external services expenditures related to Coyote s 2006 maintenance shutdown.

The increases in depreciation and amortization expense and property taxes are related to an increase in electric plant in service in 2007 compared with 2006.

Plastics

(in thousands)	Nine months ended September 30, 2007	2006	Change	% Change
Operating revenues	$ 114,319	$ 136,731	$ (22,412)	(16.4)
Cost of goods sold	93,565	103,794	(10,229)	(9.9)
Operating expenses	5,073	6,790	(1,717)	(25.3)
Depreciation and amortization	2,298	2,101	197	9.4
Operating income	$ 13,383	$ 24,046	$ (10,663)	(44.3)

Operating revenues for the plastics segment decreased as result of a 20.0% decrease in the price per pound of pipe sold, partially offset by a 4.7% increase in pounds of pipe sold between the periods. The decrease in pipe prices and cost of goods sold reflects the effect of a 17.5% decrease in PVC resin prices between the periods. The decrease in plastics segment operating expenses reflects a decrease in sales and employee incentives directly related to the decreases in sales and operating income between the periods. The increase in depreciation and amortization expense is the result of $5.5 million in capital expenditures in 2006, mainly for production equipment.

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Manufacturing

(in thousands)	Nine months ended September 30, 2007	2006	Change	% Change
Operating revenues	$ 286,341	$ 226,555	$ 59,786	26.4
Cost of goods sold	225,670	178,970	46,700	26.1
Operating expenses	25,839	19,668	6,171	31.4
Depreciation and amortization	9,734	8,124	1,610	19.8
Operating income	$ 25,098	$ 19,793	$ 5,305	26.8

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

Revenues at DMI increased $46.9 million as a result of increased production levels at the Ft. Erie plant compared with initial start-up levels beginning in May 2006, contributing $22.4 million to the increase in revenues, and increased productivity at the West Fargo plant.

Revenues at ShoreMaster increased $8.9 million between the periods due to increased production and sales of commercial products and higher residential sales during the peak selling season. The Aviva Sports product line, acquired by ShoreMaster in February 2007, contributed $2.9 million to the increase in revenues.

Revenues at BTD increased $2.0 million between the periods mainly as a result of the May 2007 acquisition of Pro Engineering, which contributed $2.5 million to 2007 revenues, partially offset by reduced unit sales at BTD s other manufacturing facilities.

Revenues at T.O. Plastics increased $1.9 million between the periods as a result of an 18.7% increase in unit sales partially offset by an 11.7% decrease in the average price per unit sold, which also reflects a change in the level of sales of lower-priced products relative to higher-priced products between the periods.

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

Cost of goods sold at DMI increased $38.3 million between the periods, including $29.8 million in material costs increases and $5.9 million in labor and benefit cost increases. The increase in cost of goods sold is directly related to DMI s increase in production and sales activity, including operations at the Ft. Erie facilities which commenced in May 2006.

Cost of goods sold at ShoreMaster increased $5.1 million between the periods as a result of increases in material and labor costs directly related to the increase in commercial and residential product sales and the acquisition of the Aviva Sports product line in February 2007 which contributed $2.2 million to cost of goods sold in 2007.

Cost of goods sold at BTD increased $1.4 million between the periods as a result of increases in material and subcontractor costs mainly related to the acquisition of Pro Engineering in May 2007, partially offset by a decrease in costs at BTD s other manufacturing facilities related to a decrease in unit sales between the periods.

Cost of goods sold at T.O. Plastics increased $1.9 million, including $1.1 million in material cost increases and $0.7 million in increased manufacturing overhead costs related to increased production.

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

Operating expenses at DMI increased $2.4 million as a result of increases in labor and benefit, professional services and promotional expenses mainly related to operations at the Ft. Erie facilities which commenced in May 2006. DMI s 2007 operating expenses include $0.4 million in pre-production start-up costs at its new Tulsa, Oklahoma plant.

Operating expenses at ShoreMaster increased $2.4 million as a result of increases in labor, benefit and professional service, and sales expenses, of which $1.1 million is related to the Aviva Sports product line acquired in February 2007.

Operating expenses at BTD increased $1.0 million between the periods as a result of increases in labor and professional service expenses mainly related to the acquisition of Pro Engineering in May 2007.

Operating expenses at T.O. Plastics increased by $0.4 million between the periods mainly as a result of increases in labor and contracted service expenditures.

Depreciation expense increased between the periods mainly as a result of capital additions at DMI s Ft. Erie plant in 2006.

In January 2007, DMI announced plans to expand wind tower production capacity at its Ft. Erie plant. The two-phase expansion project will also allow DMI to manufacture larger tower sections at that plant. The first phase became operational in April 2007. In May 2007, DMI announced plans to add a third wind tower manufacturing facility in Tulsa, Oklahoma. The Tulsa plant is expected to be operational in 2008.

Health Services

(in thousands)	Nine months ended September 30, 2007	2006	Change	% Change
Operating revenues	$ 96,775	$ 100,341	$ (3,566)	(3.6)
Cost of goods sold	72,425	78,147	(5,722)	(7.3)
Operating expenses	17,733	16,768	965	5.8
Depreciation and amortization	2,986	2,733	253	9.3
Operating income	$ 3,631	$ 2,693	$ 938	34.8

Revenues from scanning and other related services decreased $1.8 million as a result of a $0.9 million decrease in revenues from rental and interim installations and a 6.5% decrease in the number of scans performed between the periods. Revenues from equipment sales and servicing decreased $1.8 million between the periods as a decrease in traditional dealership distribution of products was mostly offset by increases in manufacturer representative commissions on more manufacturer-direct sales. The decrease in health services revenue was more than offset by the decrease in health services cost of goods sold due to the decrease in traditional dealership distribution of products and $2.0 million in decreases to labor, warranty and other direct costs of sales. The $1.0 million increase in operating expenses is mainly due to increased labor, advertising, promotional and contracted service expenditure. The increase in depreciation and amortization expense is due to $4.7 million in capital expenditures in 2006.

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Food Ingredient Processing

(in thousands)	Nine months ended September 30, 2007	2006	Change	% Change
Operating revenues	$ 53,612	$ 30,635	$ 22,977	75.0
Cost of goods sold	43,229	30,419	12,810	42.1
Operating expenses	2,334	2,203	131	5.9
Depreciation and amortization	2,985	2,805	180	6.4
Operating income (loss)	$ 5,064	$ (4,792)	$ 9,856	205.7

The increase in food ingredient processing revenues reflects a 45.2% increase in pounds of product sold combined with a 20.6% increase in the price per pound sold. Approximately 5.0% of increased product sales are in Europe due, in part, to a poor European potato crop in 2006. The increase in revenues was only partially offset by a 42.1% increase in cost of goods sold. The cost per pound of product sold decreased 2.1% between the periods as a result of decreases in raw potato and natural gas prices. The increase in operating expenses between the periods is mainly due to increases in employee benefit expenses and insurance costs. The increase in depreciation and amortization expense is related to $1.8 million in capital additions in 2006.

Other Business Operations

(in thousands)	Nine months ended September 30, 2007	2006	Change	% Change
Operating revenues	$ 129,012	$ 99,397	$ 29,615	29.8
Cost of goods sold	87,785	59,702	28,083	47.0
Operating expenses	43,714	41,255	2,459	6.0
Depreciation and amortization	1,902	2,158	(256)	(11.9)
Operating loss	$ (4,389)	$ (3,718)	$ (671)	(18.0)

Corporate general and administrative expenses included in the operating losses from other business operations were $9.4 million and $9.1 million for the nine months ended September 30, 2007 and 2006, respectively. Net operating income from other business operations before corporate general and administrative expenses was $5.0 million and $5.4 million for the nine months ended September 30, 2007 and 2006, respectively.

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

Revenues at MCS increased $18.1 million between the periods as a result of an increase in volume of jobs in progress.

Revenues at Foley Company increased $10.6 million between the periods due to an increase in the volume of jobs in progress.

Revenues at Wylie increased $0.2 million between the periods mainly due to a 3.8% increase in miles driven by owner-operated and company-operated trucks. Miles driven by company-operated trucks increased 9.9% and miles driven by owner-operated trucks decreased 5.0% between the periods.

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

Cost of goods sold at MCS increased $17.4 million mainly due to increases in material, subcontractor and labor costs related to the increase in volume of jobs in progress between the periods.

Cost of goods sold at Foley Company increased $10.8 million mainly in the areas of subcontractor and labor costs as a result of the increased volume of work performed between the periods.

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

Corporate operating expenses in this segment increased $1.0 million as a result of higher labor and equipment rental costs.

Operating expenses at Wylie increased $1.0 million between the periods, mainly as a result of increases in fuel, equipment rental and labor expenses, partly offset by a decrease in subcontractor costs related to the decrease in miles driven by owner-operated trucks. Wylie s depreciation expense decreased $0.4 million between the periods as a result of leasing rather than buying replacement equipment.

Operating expenses at MCS increased $0.2 million and its depreciation expense increased $0.1 million between the periods.

Operating expenses at Foley Company increased $0.2 million between the periods.

Income Taxes Continuing Operations

Income tax expense increased $1.4 million in the nine months ended September 30, 2007 compared with the nine months ended September 30, 2006 as a result of a $1.8 million increase in income before income taxes from continuing operations between the periods and a reduction of $0.6 million in income tax liabilities in the third quarter of 2006 related to closed income tax returns. The effective tax rate for continuing operations was 36.8% for the nine months ended September 30, 2007 compared with 35.5% for the nine months ended September 30, 2006.

Discontinued Operations

In June 2006, OTESCO sold its gas marketing operations for $0.5 million in cash. SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* requires that OTESCO s gas marketing operations be classified and reported separately as discontinued operations. The results of discontinued operations for the nine months ended September 30, 2006 are summarized as follows:

(in thousands)		Nine months ended September 30, 2006
Income before income taxes	$	54
Gain on disposition pretax		560
Income tax expense		252
Net income	$	362

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2007 EXPECTATIONS

The statements in this section are based on our current outlook for 2007 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 anticipate 2007 diluted earnings per share from continuing operations to be in a range from $1.60 to $1.80. Contributing to the earnings guidance for 2007 are the following items:

- We expect electric segment earnings in the range of $19.0 million to $24.0 million in 2007, which is consistent with 2007 prior guidance. A major maintenance shutdown of Big Stone Plant planned for the third quarter of 2007 was rescheduled for the fourth quarter of 2007, resulting in a shift in anticipated expenditures and plant availability between the quarters.

- We expect our plastics segment s earnings performance to be in the range of $6.0 million to $8.5 million in 2007, which is consistent with 2007 prior guidance.

- We expect continued enhancements in productivity and capacity utilization and strong backlogs to result in increased net income in our manufacturing segment in 2007.

- We expect flat to slightly declining earnings in our health services segment in 2007 primarily due to lower sales at the diagnostic imaging services company. This is a change from prior guidance of moderate net income growth from this segment in 2007.

- We expect our food ingredient processing business (IPH) to generate net income in the range of $3.0 million to $4.5 million in 2007, a change from prior guidance of $2.5 million to $4.5 million.

- We expect our other business operations segment to have lower earnings in 2007 compared with 2006 due to an expected return to more normal corporate cost levels. We expect our construction companies to have a strong 2007 given performance in the first nine months of 2007 and current backlogs.

FINANCIAL POSITION

For the period 2007 through 2011, we estimate funds internally generated net of forecasted dividend payments will be sufficient to fund a portion of planned capital expenditures and to meet scheduled debt retirements (excluding the scheduled retirement of the $50 million 6.375% senior debentures due December 1, 2007, which is scheduled to be refinanced under a note purchase agreement between the Company and Cascade Investment L.L.C. (Cascade) discussed below). 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 2008 through 2011 given the expansion plans related to our electric segment to fund the construction of the proposed new Big Stone II generating station at the Big Stone Plant site, the Langdon Wind Project discussed below, other wind and transmission projects, and a wind tower manufacturing facility in Tulsa, Oklahoma, in the event we decide to refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions 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.

On March 29, 2007 Otter Tail Power Company and Minnkota Power Cooperative announced they had entered into an agreement with FPL Energy to develop the Langdon Wind Project, a 159 megawatt (MW) wind farm to be constructed south of Langdon, North Dakota, with an expected completion date in late 2007 or early 2008. Otter Tail Power Company s participation in the project includes the ownership of 27 wind turbines rated at 1.5 MW each and a 25-year power purchase agreement with Langdon Wind, LLC to purchase the electricity generated from

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13 other wind turbines at the site. Contracts related to construction of the 27 wind towers and turbines to be owned by Otter Tail Power Company will increase our 2007 purchase obligations by $86.5 million.

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.

At September 30, 2007, we had outstanding a $150 million line of credit pursuant to a Credit Agreement dated as of April 26, 2007 among us, 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 (the Company Credit Agreement). As of September 30, 2007, $68.0 million of the line of credit was in use and $15.7 million was restricted from use to cover outstanding letters of credit. The Company Credit Agreement was terminated and replaced by a new credit agreement entered into by Varistar Corporation (Varistar) on October 2, 2007.

On October 2, 2007 Varistar entered into a $200 million Credit Agreement (the Varistar Credit Agreement) with the following banks: U.S. Bank National Association as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. The Varistar Credit Agreement is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Varistar Credit Agreement expires on October 2, 2010. Borrowings under the line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on Varistar s adjusted cash flow leverage ratio. The Varistar Credit Agreement replaces the Company Credit Agreement. The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Varistar Credit Agreement also contains certain financial covenants. Specifically, Varistar must maintain a fixed charge coverage ratio of not less than 1.25 to 1.00 and must not permit its cash flow leverage ratio to exceed 3.00 to 1.00. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Varistar s obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Outstanding letters of credit issued by Varistar can reduce the amount available for borrowing under the line by up to $30 million.

On September 1, 2006 Otter Tail Corporation, dba Otter Tail Power Company and U.S. Bank National Association entered into a Credit Agreement (the Otter Tail Power Company Credit Agreement) providing for a separate $25 million line of credit. This line of credit is an unsecured revolving credit facility that Otter Tail Power Company can draw on to support the working capital needs and other capital requirements of its electric operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of our senior unsecured debt. The Otter Tail Power Company Credit Agreement contains a number of restrictions on the business of Otter Tail Power Company, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Otter Tail Power Company Credit Agreement also contains certain financial covenants. Specifically, the Company must not permit its debt-to-total capitalization ratio to exceed 60% or permit its interest and dividend coverage ratio to be less than 1.5 to 1.

On April 13, 2007 the parties to the Otter Tail Power Company Credit Agreement entered into a First Amendment to Credit Agreement which increased the commitment from $25 million to $50 million. On August 31, 2007 the parties entered into a Second Amendment to the Credit Agreement which further increased the commitment from $50 million to $75 million, and which extended the termination date from September 1, 2007 to September 1, 2008. As of September 30, 2007, $10.8 million was borrowed under the Otter Tail Power Company Credit Agreement.

In February 2007 we entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which we agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of our senior notes due November 30, 2017. Cascade owned approximately 8.7% of our outstanding common stock as of June 30, 2007. The notes will bear interest at a rate of 5.778% per annum, subject to adjustment in the event certain ratings assigned to our long-term senior unsecured indebtedness are downgraded below specific levels prior to the closing of the note purchase. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of our $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The closing is expected to occur on December 3, 2007 subject to the satisfaction of certain conditions to closing, including: (i) no event or events will have occurred since December 31, 2005 that have had or would reasonably be expected to have a material adverse effect on us and our subsidiaries taken as a whole; (ii) certain senior executives will remain in their current positions; (iii) there is no change in control or impermissible sale of assets; (iv) the ratio of our consolidated debt to earnings before interest, taxes, depreciation and amortization as of September 30, 2007 will be less than 3.5 to 1; (v) certain waivers will have been obtained; and (vi) certain other customary conditions of closing will have been satisfied. The proceeds of this financing will be used to redeem our $50 million 6.375% Senior Debentures due December 1, 2007.

At closings completed in August 2007 and October 2007, we issued $155 million aggregate principal amount of our senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007 between us and these purchasers. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The net proceeds from this initial closing were used to repay borrowings under the Company Credit Agreement. The remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes, were issued and sold by us at a second closing on October 1, 2007. The net proceeds from the second closing were used to retire $40 million aggregate principal amount of our 5.625% Series of Insured Senior Notes due October 1, 2017 and $25 million aggregate principal amount of our 6.80% Series of Senior Notes due October 1, 2032 on October 15, 2007, to pay down lines of credit and to fund capital expenditures.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, and the 2001 Note Purchase Agreement states we may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require us to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreement. The 2007 Note Purchase Agreement states we must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of the Company.

The 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement contain a number of restrictions on the businesses of us and our subsidiaries, and the Cascade Note Purchase Agreement contains similar restrictions that will be effective upon issuance to Cascade of the notes thereunder. In each case these include restrictions on the ability of us and certain of our subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements and

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the Lombard US Equipment Finance loan agreement also contain covenants by us not to permit our debt-to-total capitalization ratio to exceed 60% or permit our interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, our interest charges coverage ratio) to be less than 1.5 to 1, determined as of the end of a fiscal quarter for the preceding twelve-month period. The note purchase agreements further restrict us from allowing our priority debt to exceed 20% of total capitalization. We were in compliance with all of the covenants under our financing agreements as of September 30, 2007.

Our obligations under the 2001 Note Purchase Agreement are, and our obligations under the Cascade Note Purchase Agreement will be, guaranteed by certain of our subsidiaries. Varistar s obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Our Grant County and Mercer County Pollution Control Refunding Revenue Bonds require that we grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds, 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 securities ratings at September 30, 2007 were:

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

In July 2007, Moody s changed its outlook on Otter Tail Corporation from stable to negative, citing risks of recovery associated with planned capital expenditures in the electric segment as a major factor contributing to its outlook change. In September 2007, Standard & Poor s changed its outlook on Otter Tail Corporation from stable to negative, citing continued growth of nonregulated businesses and a large capital spending program in the electric segment as the reasons for its outlook change. 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 of continuing operations was $57.3 million for the nine months ended September 30, 2007 compared with $42.7 million for the nine months ended September 30, 2006. The $14.6 million increase in cash provided by operating activities of continuing operations reflects an $11.2 million decrease in cash used for working capital items from $37.6 million in the first nine months of 2006 to $26.4 million in the first nine months of 2007. The increase in cash provided by operating activities of continuing operations also reflects increases in net deferred income tax liabilities of $2.7 million.

Major uses of funds for working capital items in the first nine months of 2007 were an increase in receivables of $26.9 million and a decrease in payables and other current liabilities of $15.2 million, offset by decreases in inventories of $7.8 million and other current assets of $3.6 million and an increase in interest and income taxes payable of $4.4 million. The $26.9 million increase in receivables includes $12.1 million at DMI related to increased sales of wind towers, $7.7 million from our construction companies related to increased activity and billings during the summer construction season and $7.2 million from our plastic pipe companies related to higher sales in the third quarter of 2007 compared to the fourth quarter of 2006. The decrease in payables and other current liabilities is mainly due to a $15.1 million reduction in DMI s billings in excess of costs and estimated earnings on uncompleted contracts. The decrease in inventories reflects reductions in finished goods inventory of $3.2 million at our plastic pipe companies and $1.7 million at IPH, which is normal at the end of a processing season, and reductions in raw inventory of $1.9 million at MCS as inventory is being used on billable jobs and $0.7 million at DMI due to better

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inventory management, which has improved DMI s working capital. The decrease in other current assets is due to an $11.2 million decrease in accrued FCA and unbilled revenues at the electric utility, offset by increases of $3.5 million in costs in excess of billings at DMI and $3.5 million in prepaid insurance across all our operating companies related to the timing of premium payments. The increase in interest and income taxes payable reflects a $2.5 million increase in interest payable and a $1.9 million increase in income taxes payable which is generally the norm between December and September due to the timing of interest payments on long-term debt and estimated tax payments.

Net cash used in investing activities of continuing operations was $103.7 million for the nine months ended September 30, 2007 compared with $53.2 million for the nine months ended September 30, 2006. Cash used for capital expenditures increased by $46.1 million between the periods. Cash used for capital expenditures at the electric utility increased by $33.5 million between the periods mainly related to initiation of the Langdon Wind Project in the second quarter of 2007 and replacement of the flue-gas treatment system at Big Stone Plant. Cash used for capital expenditures at DMI increased $12.8 million between the periods mainly due to the purchase of property and equipment for a new wind tower manufacturing facility being constructed in Tulsa, Oklahoma. We completed two acquisitions during the first nine months of 2007 for a combined purchase price of $6.8 million. No acquisitions were completed in 2006. The net increase in proceeds from the disposal of noncurrent assets and cash used for other investments of $2.4 million is mainly due to the sales of short-term investments and the reinvestment of proceeds from those sales by our captive insurance company in the first six months of 2007.

Net cash provided by financing activities was $43.0 million for the nine months ended September 30, 2007 compared with net cash provided by financing activities of $10.6 million for the nine months ended September 30, 2006. Proceeds from the issuance of long-term debt increased $25.0 million between the periods as a result of the issuance of $12 million aggregate principal amount of our Series C Notes and $13 million aggregate principal amount of our Series D Notes on August 20, 2007. Proceeds from these issuances were used to pay down our lines of credit which were being used to fund capital expenditures. Proceeds from the issuance of common stock increased $6.0 million due to an increase in the number of stock options exercised in the first nine months of 2007 compared with the first nine months of 2006. In the first nine months of 2007 we issued 293,382 common shares for stock options exercised. During the same period, we retired 8,409 common shares for tax withholding purposes related to restricted shares that vested in 2007. Cash proceeds from short-term borrowings and checks written in excess of cash increased by $1.9 million between the periods.

Our estimated capital expenditures by segment for 2007 and the years 2007 through 2011 are as follows:

(in millions)	2007	2007-2011
Electric	$ 125	$ 680
Plastics	5	19
Manufacturing	38	78
Health services	4	12
Food ingredient processing	1	17
Other business operations	4	9
Total	$ 177	$ 815

Current estimated capital expenditures for our share of Big Stone II are $320 million. This estimate of our portion of the costs assumes an in service date in 2013 with the best available information. Any change in schedule for the project could increase our portion of the costs.

Otter Tail Power Company s integrated resource plan (IRP) includes generation from Big Stone II, a proposed coal-fired base-load generation unit, beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. Approval of this IRP is pending with the Minnesota Public Utilities Commission, along with a Certificate of Need for transmission lines

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located in Minnesota that are required for interconnection of the Big Stone II project to the transmission grid. Additionally, a filing in North Dakota for an advanced determination of prudence of Big Stone II was made in November 2006. In September 2007, two project participants, Great River Energy and Southern Minnesota Municipal Power Agency, announced their intention to withdraw from the project. The five remaining project participants are currently assessing options for downsizing the plant or adding new participants. New procedural schedules are being established in the various project-related proceedings, which will take into consideration the optimal plant configuration decided on by the remaining participants.

In February 2007 the South Dakota Appeals Court issued an opinion affirming the decision of the South Dakota Public Utilities Commission to grant a siting permit for Big Stone II. The permit has now been appealed to the South Dakota Supreme Court, which is expected to hear the appeal during its fall session.

As of September 30, 2007 Otter Tail Power Company had capitalized $8.1 million in costs related to the planned construction of Big Stone II. 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 may be subject to expense and may not be recoverable.

There were changes in our contractual obligations in the first nine months of 2007 from those reported under the caption Capital Requirements on page 25 of our 2006 Annual Report to Shareholders. These include increases in: (1) Long-term debt obligations and Interest on long-term debt obligations related to our August and October 2007 debt issuances and retirements, (2) operating lease obligations related to a three-year agreement to lease new rail cars for the shipment of coal to Hoot Lake Plant signed in August 2007, (3) capacity and energy requirements related to the 25-year power purchase agreement to purchase electricity generated from 13 other turbines at the same site beginning in late 2007 or early 2008 and (4) other purchase obligations related to the Langdon Wind Project of approximately $86.5 million in 2007.

- The increase in Long-term debt obligations is $90.0 million in the years beyond 2011.

- The increases in Interest on long-term debt obligations are $0.2 million in 2007, $10.5 million in 2008 and 2009 combined, $11.6 million in 2010 and 2011 combined and $109.9 million in the years beyond 2011.

- The increases in operating lease obligations will be $0.4 million in 2007, $2.1 million in 2008 and 2009 combined and $0.7 million in 2010.

- The increases in capacity and energy requirements are estimated to be $5.4 million in 2008 and 2009 combined, $5.4 million in 2010 and 2011 combined and $56.7 million in the years beyond 2011. This power purchase agreement is for energy only and includes no capacity payment requirements.

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

Critical Accounting Policies Involving Significant Estimates

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

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, uncertain

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tax positions, 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 and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors. A discussion of critical accounting policies is included under the caption Critical Accounting Policies Involving Significant Estimates on pages 30 through 32 of our 2006 Annual Report to Shareholders. There were no material changes in critical accounting policies or estimates during the nine months ended September 30, 2007, except for the adoption of Financial Accounting Standards Board Interpretation (FIN) No. 48 on January 1, 2007.

Goodwill Impairment

We currently have $24.3 million of goodwill and a $3.2 million nonamortizable trade name recorded on our balance sheet related to the acquisition of IPH in 2004. If operating margins do not continue to 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 nonamortizable intangible assets and a corresponding charge against earnings.

We evaluate goodwill for impairment on an annual basis and as conditions warrant. As of December 31, 2006 an assessment of the carrying values of our goodwill indicated no impairment.

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

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

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

- We are subject to federal and state legislation, regulations and actions that may have a negative impact on our business and results of operations.
- Future operating results of our electric segment will be impacted by the outcome of a rate case filed in Minnesota on October 1, 2007, requesting an overall increase in Minnesota rates of 6.66%. The filing includes a request for an interim rate increase of 5.41% beginning November 30, 2007. If approved by the Minnesota Public Utilities Commission (MPUC), interim rates will remain in effect for all Minnesota customers until the MPUC makes a final determination on the electric utility s request, which is expected by August 1, 2008. If final rates are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

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Certain costs currently included in the FCA in retail rates may be excluded from recovery through the FCA but may be subject to recovery through rates established in a general rate case. Further, all, or portions of, gross margins on asset-based wholesale electric sales may become subject to refund through the FCA as a result of a general rate case.

Weather conditions or changes in weather patterns can adversely affect our operations and revenues.

Electric wholesale margins could be further reduced as the MISO market becomes more efficient.

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

Our electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

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

Our electric segment has capitalized $8.1 million in costs related to the planned construction of a second electric generating unit at our Big Stone Plant site as of September 30, 2007. 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 may be subject to expense and may not be recoverable.

Our manufacturer of wind towers operates in a market that has been dependent on the Federal Production Tax Credit. This tax credit is currently in place through December 31, 2008. 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.

Existing or new laws or regulations addressing climate change or reductions of greenhouse gas emissions by federal or state authorities, such as mandated levels of renewable generation or mandatory reductions in carbon dioxide (CO_2) emission levels or taxes on CO_2 emissions, that result in increases in electric service costs could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where the electric utility provides service or through increased market prices for electricity.

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

Our plan to grow our nonelectric businesses could be limited by state law.

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 and changes in our debt rating could restrict our ability to access capital and could increase borrowing costs and pension plan expenses.

The price and availability of raw materials could affect the revenue and earnings of our manufacturing segment.

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

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

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

A significant failure or an inability to properly bid or perform on projects by our construction businesses could lead to adverse financial results.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At September 30, 2007 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 30% 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. As of September 30, 2007 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, 2007, annualized interest expense and pre-tax 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, 2007 the electric utility had recognized, on a pretax basis, $5,000 in net unrealized losses 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 or brokers used by the electric utility s power services personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. Prices are benchmarked to regional hub prices as published in *Megawatt Daily* and forward price curves and indices acquired from a third party price forecasting service. Of the forward energy contracts that are marked to market as of September 30, 2007, all of the forward sales of electricity had offsetting purchases in terms of volumes and delivery periods, except for two contracts for the purchase of 72,100 mwhs in November 2007 to replace generation from our Big Stone Plant when it is shutdown for scheduled maintenance. As of September 30, 2007 we had a derivative liability of $451,000 associated with these contracts with the offsetting derivative loss recorded as a regulatory asset as the costs of these contracts will be recoverable in retail rates in the period of delivery or settlement or in subsequent periods through fuel clause adjustments.

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 and financial transactions in the MISO Day 2 markets that employ volumetric limits and loss limits and Value at Risk (VaR) limits to adequately manage the risks associated with these activities. Exposure to price risk on any open positions as of September 30, 2007 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, 2007 and the change in our consolidated balance sheet position from December 31, 2006 to September 30, 2007:

(in thousands)	September 30, 2007
Current asset marked-to-market gain	$ 3,734
Regulatory asset deferred marked-to-market loss	451
Current liability marked-to-market loss	(4,190)
Net fair value of marked-to-market gas contracts	$ (5)

(in thousands)	Year-to-date September 30, 2007
Fair value at beginning of year	$ 203
Amount realized on contracts entered into in 2006 and settled in 2007	(203)
Changes in fair value of contracts entered into in 2006	
Net fair value of contracts entered into in 2006 at end of period	
Changes in fair value of open contracts entered into in 2007	(5)
Net fair value end of period	$ (5)

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The $5,000 recognized but unrealized net losses on the forward energy purchases and sales marked to market on September 30, 2007 is expected to be realized on physical settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	4th Quarter 2007	1st Quarter 2008	Total
Net (loss) gain	$(418)	$413	$(5)

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, 2007 was $1.9 million. This counterparty has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. As of September 30, 2007 we had a net credit risk exposure of $3.2 million from 14 counterparties with investment grade credit ratings. We had no exposure at September 30, 2007 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 $5.1 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, 2007. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

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 were derivatives subject to mark-to-market accounting but they did not qualify for hedge accounting treatment. IPH includes net changes in the market values of these forward contracts in net income as components of cost of goods sold in the period of recognition. Of the $371,000 in unrealized marked-to-market losses on forward natural gas contracts IPH had outstanding on December 31, 2006, $62,000 was reversed and $309,000 was realized on settlement in the first quarter of 2007.

Item 4. Controls and Procedures

Under the supervision and with the participation of the Company s management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of September 30, 2007, 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, 2007.

During the fiscal quarter ended September 30, 2007, there were no changes in the Company s internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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 29 of the Company s 2006 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, 2006, except to revise the first risk factor under the heading General for specific financial risks related to climate change legislation or regulations and to revise the second risk factor under the heading Electric to address interim rates requested in our general rate case filed in Minnesota on October 1, 2007 and to indicate that MISO schedule 16 and 17 costs are no longer subject to recovery through the FCA in North Dakota as set forth below.

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

We are subject to federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and health safety. These laws and regulations regulate the modification and operation of existing facilities, the construction and operation of new facilities and the proper storage, handling, cleanup and disposal of hazardous waste and toxic substances. Compliance with these legal requirements requires us to commit significant resources and funds toward environmental monitoring, installation and operation of pollution control equipment, payment of emission fees and securing environmental permits. Obtaining environmental permits can entail significant expense and cause substantial construction delays. Failure to comply with environmental laws and regulations, even if caused by factors beyond our control, may result in civil or criminal liabilities, penalties and fines.

Existing environmental laws or regulations may be revised and new laws or regulations may be adopted or become applicable to us. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

Existing or new laws or regulations addressing climate change or reductions of greenhouse gas emissions by federal or state authorities, such as mandated levels of renewable generation or mandatory reductions in carbon dioxide (CO_2) emission levels or taxes on CO_2 emissions, that result in increases in electric service costs could negatively impact the corporation s net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where the electric utility provides service or through increased market prices for electricity.

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

We are subject to federal and state legislation, government regulations and regulatory actions that may have a negative impact on our business and results of operations. The electric rates that we are allowed to charge for our electric services are one of the most important items influencing our financial position, results of operations and liquidity. The rates that we charge our electric customers are subject to review and determination by state public utility commissions in Minnesota, North Dakota and South Dakota. We are also regulated by the Federal Energy Regulatory Commission. An adverse decision by one or more regulatory commissions concerning the level or method of determining electric utility rates, the authorized returns on equity, implementation of enforceable federal reliability standards or other regulatory matters, permitted business activities (such as ownership or operation of nonelectric businesses) or any prolonged delay in rendering a decision in a rate or other proceeding (including with respect to the recovery of capital expenditures in rates) could result in lower revenues and net income.

Future operating results of our electric segment will be impacted by the outcome of a rate case filed in Minnesota on October 1, 2007 requesting an overall increase in Minnesota rates of 6.66%. The filing includes a request for an interim rate increase of 5.41% beginning November 30, 2007. If approved by the Minnesota Public Utilities Commission (MPUC), interim rates will remain in effect for all Minnesota customers until the MPUC makes a final determination on the electric utility s request, which is expected by August 1, 2008. If final rates are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

Recovery of MISO schedule 16 and 17 administrative costs associated with providing electric service to Minnesota and North Dakota customers are currently being deferred pending the outcomes of our general rate case filed in Minnesota on October 1, 2007 and our next general rate case in North Dakota, which we agreed to file in November or December of 2008. If we are not granted recovery of the MISO schedule 16 and 17 administrative costs deferred as of the rate case decision dates, we could be required to recognize these costs immediately in expense at the time recovery is denied.

Item 6. Exhibits

4.1 Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Corporation and each of Deutsche Bank AG New York Branch, Teachers Insurance and Annuity Association of America, Provident Life and Accident Insurance Company, The Guardian Life Insurance Company of America, Thrivent Financial For Lutherans, Fort Dearborn Life Insurance Company, The Catholic Aid Association, Great West Insurance Company, American Republic Insurance Company, Cincinnati Insurance Company, Colorado Bankers Life Insurance Company, Navy Mutual Aid Association and National Guardian Life Insurance Company (incorporated by reference to Exhibit 4.1 to Otter Tail Corporation s Form 8-K filed August 23, 2007)

4.2 Second Amendment to Credit Agreement dated as of August 31, 2007 between Otter Tail Corporation dba Otter Tail Power Company and U.S. Bank National Association (amending the 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 Otter Tail Corporation s Form 8-K filed September 6, 2007)

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10.1 Amendment No. 5 to Participation Agreement, dated as of September 1, 2007, 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., Otter Tail Corporation dba Otter Tail Power Company, Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency, as Owners, amending the Participation Agreement, dated as of June 30, 2005, by and among the Owners (incorporated by reference to Exhibit 10.1 to Otter Tail Corporation s Form 8-K filed September 12, 2007)

10.2 Amendment No. 6 to Participation Agreement, dated as of September 20, 2007, 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., Otter Tail Corporation dba Otter Tail Power Company, Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency, as Owners, amending the Participation Agreement, dated as of June 30, 2005, by and among the Owners (incorporated by reference to Exhibit 10.1 to Otter Tail Corporation s Form 8-K filed September 24, 2007)

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

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SIGNATURES

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

OTTER TAIL CORPORATION

By: /s/ Kevin G. Moug

Kevin G. Moug
Chief Financial Officer and Treasurer
(Chief Financial Officer/Authorized Officer)

Dated: November 9, 2007

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