OTTER TAIL CORP
Form 10-Q
August 09, 2006

Table of Contents

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 June 30, 2006

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:

July 31, 2006 29,466,245 Common Shares ($5 par value)

OTTER TAIL CORPORATION
INDEX

			Page No.
Part I. Financial Information			
	Item 1.	Financial Statements	
		Consolidated Balance Sheets June 30, 2006 and December 31, 2005 (not audited)	2 & 3
		Consolidated Statements of Income Three and Six Months Ended June 30, 2006 and 2005 (not audited)	4
		Consolidated Statements of Cash Flows Six Months Ended June 30, 2006 and 2005 (not audited)	5
		Notes to Consolidated Financial Statements (not audited)	6-21
	Item 2.	Management s Discussion and Analysis of Financial Condition and Results of Operations	22-41
	Item 3.	Quantitative and Qualitative Disclosures About Market Risk	41-43
	Item 4.	Controls and Procedures	43
Part II. Other Information			
	Item 1.	Legal Proceedings	44
	Item 1A.	Risk Factors	44
	Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	44
	Item 4.	Submission of Matters to a Vote of Security Holders	45
	Item 5.	Other Information	45-46
	Item 6.	Exhibits	46
Signatures			47

Form of 2006 Restricted Stock Unit Award Agreement
Amendment to Participation Agreement
Certification of CEO Pursuant to Section 302
Certification of CFO Pursuant to Section 302
Certification of CEO Pursuant to Section 906
Certification of CFO Pursuant to Section 906

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	June 30, 2006	December 31, 2005
	(Thousands of dollars)	
Current assets		
Cash and cash equivalents	$	$ 5,430
Accounts receivable:		
Trade net	136,147	117,796
Other	9,581	11,790
Inventories	106,989	88,677
Deferred income taxes	6,780	6,871
Accrued utility revenues	24,634	22,892
Costs and estimated earnings in excess of billings	41,826	21,542
Other	17,376	16,476
Assets of discontinued operations	600	13,701
Total current assets	343,933	305,175
Investments and other assets	34,825	33,824
Goodwill net	98,110	98,110
Other intangibles net	20,636	21,160
Deferred debits		
Unamortized debt expense and reacquisition premiums	6,408	6,520
Regulatory assets and other deferred debits	17,164	19,616
Total deferred debits	23,572	26,136
Plant		
Electric plant in service	917,838	910,766
Nonelectric operations	232,267	228,548
Total plant	1,150,105	1,139,314
Less accumulated depreciation and amortization	473,884	459,438
Plant net of accumulated depreciation and amortization	676,221	679,876
Construction work in progress	35,804	17,215
Net plant	712,025	697,091
Total	$ 1,233,101	$ 1,181,496

See accompanying notes to consolidated financial statements

Table of Contents

Consolidated Balance Sheets
(not audited)
-Liabilities-

	June 30, 2006	December 31, 2005
	(Thousands of dollars)	
Current liabilities		
Short-term debt	$ 59,032	$ 16,000
Current maturities of long-term debt	3,232	3,340
Accounts payable	106,297	97,239
Accrued salaries and wages	21,122	24,326
Accrued federal and state income taxes	18,143	8,449
Other accrued taxes	8,971	12,518
Other accrued liabilities	13,884	14,124
Liabilities of discontinued operations	242	10,983
Total current liabilities	230,923	186,979
Pensions benefit liability	22,257	23,216
Other postretirement benefits liability	27,901	26,982
Other noncurrent liabilities	17,313	18,683
Deferred credits		
Deferred income taxes	113,921	113,737
Deferred investment tax credit	8,754	9,327
Regulatory liabilities	60,560	61,624
Other	1,445	1,500
Total deferred credits	184,680	186,188
Capitalization		
Long-term debt, net of current maturities	256,850	258,260
Class B stock options of subsidiary	1,258	1,258
Cumulative preferred shares authorized 1,500,000 shares without par value; outstanding 2006 and 2005 155,000 shares	15,500	15,500
Cumulative preference shares authorized 1,000,000 shares without par value; outstanding none		
Common shares, par value $5 per share authorized 50,000,000 shares; outstanding 2006 29,465,129 and 2005 29,401,223	147,326	147,006
Premium on common shares	97,109	96,768

Unearned compensation		(1,720)
Retained earnings	237,571	228,515
Accumulated other comprehensive loss	(5,587)	(6,139)
Total common equity	476,419	464,430
Total capitalization	750,027	739,448
Total	$ 1,233,101	$ 1,181,496

See accompanying notes to consolidated financial statements

Table of Contents

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

	Three months ended June 30, 2006	Three months ended June 30, 2005	Six months ended June 30, 2006	Six months ended June 30, 2005
	(In thousands, except share and per share amounts)		(In thousands, except share and per share amounts)	
Operating revenues	$ 279,904	$ 245,799	$ 537,711	$ 461,883
Operating expenses				
Production fuel	11,456	10,549	26,262	25,726
Purchased power system use	17,664	19,904	36,400	31,442
Electric operation and maintenance expenses	28,049	25,334	51,456	49,252
Cost of goods sold (excludes depreciation; included below)	156,363	129,602	288,757	237,232
Other nonelectric expenses	29,306	25,628	55,554	48,284
Depreciation and amortization	12,379	11,553	24,603	22,938
Property taxes electric operations	2,551	2,408	5,169	5,081
Total operating expenses	257,768	224,978	488,201	419,955
Operating income	22,136	20,821	49,510	41,928
Other income	659	210	1,087	401
Interest charges	5,100	4,814	9,544	9,374
Income from continuing operations before income taxes	17,695	16,217	41,053	32,955
Income taxes continuing operations	6,558	5,265	15,061	10,927
Net income from continuing operations	11,137	10,952	25,992	22,028
Discontinued operations				
(Loss) income from discontinued operations net of taxes of ($41); ($86); $28 and $230 for the respective periods	(79)	(134)	26	337
Net gain on disposition of discontinued operations net of taxes of $224; $6,820; $224 and $5,769 for the respective periods	336	11,486	336	9,910
Net income from discontinued operations	257	11,352	362	10,247
Net income	11,394	22,304	26,354	32,275
Preferred dividend requirements	184	183	368	367
Earnings available for common shares	$ 11,210	$ 22,121	$ 25,986	$ 31,908

Basic earnings per common share:								
Continuing operations (net of preferred dividend requirement)	$	0.37	$	0.37	$	0.87	$	0.74
Discontinued operations	$	0.01	$	0.39	$	0.01	$	0.35
	$	0.38	$	0.76	$	0.88	$	1.09
Diluted earnings per common share:								
Continuing operations (net of preferred dividend requirement)	$	0.37	$	0.37	$	0.86	$	0.74
Discontinued operations	$	0.01	$	0.39	$	0.01	$	0.35
	$	0.38	$	0.76	$	0.87	$	1.09
Average number of common shares outstanding basic		29,392,963		29,158,140		29,359,474		29,142,118
Average number of common shares outstanding diluted		29,766,040		29,263,643		29,751,718		29,244,698
Dividends per common share	$	0.2875	$	0.2800	$	0.5750	$	0.5600

See accompanying notes to consolidated financial statements

Table of Contents

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

	Six months ended June 30, 2006	2005
	(Thousands of dollars)	
Cash flows from operating activities		
Net income	$ 26,354	$ 32,275
Adjustments to reconcile net income to net cash provided by operating activities:		
Net gain from sale of discontinued operations	(336)	(9,910)
Net income from discontinued operations	(26)	(337)
Depreciation and amortization	24,603	22,938
Deferred investment tax credit	(573)	(576)
Deferred income taxes	1,134	(3,985)
Change in deferred debits and other assets	383	3,766
Discretionary contribution to pension plan	(4,000)	(4,000)
Change in noncurrent liabilities and deferred credits	2,492	5,750
Allowance for equity (other) funds used during construction	(391)	(357)
Change in derivatives net of regulatory deferral	1,918	(830)
Stock compensation expense	1,320	668
Other net	629	157
Cash (used for) provided by current assets and current liabilities:		
Change in receivables	(14,827)	(6,885)
Change in inventories	(18,004)	(20,414)
Change in other current assets	(25,648)	(17,625)
Change in payables and other current liabilities	(7,411)	(6,124)
Change in interest and income taxes payable	10,107	8,320
Net cash (used in) provided by continuing operations	(2,276)	2,831
Net cash provided by (used in) discontinued operations	926	(419)
Net cash (used in) provided by operating activities	(1,350)	2,412
Cash flows from investing activities		
Capital expenditures	(33,949)	(27,145)
Proceeds from disposal of noncurrent assets	1,048	3,503
Acquisitions net of cash acquired		(10,661)
Increases in other investments	(1,171)	(2,269)
Net cash used in investing activities continuing operations	(34,072)	(36,572)
Net proceeds from the sales of discontinued operations	1,847	33,685
Net cash provided by investing activities discontinued operations		558
Net cash used in investing activities	(32,225)	(2,329)

Cash flows from financing activities		
Change in checks written in excess of cash	4,186	(3,329)
Net short-term borrowings	43,032	38,050
Proceeds from issuance of common stock, net of issuance expenses	1,017	4,820
Payments for retirement of common stock	(463)	(365)
Proceeds from issuance of long-term debt	105	157
Debt issuance expenses	(293)	
Payments for retirement of long-term debt	(1,691)	(3,948)
Dividends paid	(17,298)	(16,691)
Net cash provided by financing activities continuing operations	28,595	18,694
Net cash used in financing activities discontinued operations		(2,781)
Net cash provided by financing activities	28,595	15,913
Effect of foreign exchange rate fluctuations on cash	(450)	183
Net change in cash and cash equivalents	(5,430)	16,179
Cash and cash equivalents at beginning of period continuing operations	5,430	
Cash and cash equivalents at end of period continuing operations	$	$ 16,179
Supplemental cash flow information		
Cash paid during the year from continuing operations for:		
Interest (net of amount capitalized)	$ 8,624	$ 8,746
Income taxes	$ 4,867	$ 3,187
Cash paid during the year from discontinued operations for:		
Interest	$ 91	$ 100
Income taxes	$ 423	$ 2,560

See accompanying notes to consolidated financial statements

Table of Contents

OTTER TAIL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(not audited)

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

Revenue Recognition

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, and the price is fixed or determinable. In cases where significant obligations remain after delivery, revenue is deferred until such obligations are fulfilled. Provisions for sales returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as the electric utility s forward energy contracts and the energy services company s swap transactions, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with Statement of Financial Accounting Standards (SFAS) No. 133 and Emerging Issues Task Force (EITF) Issues 02-3 and 03-11. Gains and losses on forward energy contracts subject to regulatory treatment are deferred and recognized on a net basis in revenue in the period realized.

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

(in thousands)	June 30, 2006	December 31, 2005
Costs incurred on uncompleted contracts	$ 183,920	$ 194,076
Less billings to date	(184,595)	(203,862)
Plus estimated earnings recognized	20,887	22,834
	$ 20,212	$ 13,048

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)	June 30, 2006	December 31, 2005
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 41,826	$ 21,542

Billings in excess of costs and estimated earnings on uncompleted contracts	(21,614)	(8,494)
	$ 20,212	$ 13,048

Table of Contents

Adjustments and Reclassifications

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

Inventories

Inventories consist of the following:

(in thousands)	June 30, 2006	December 31, 2005
Finished goods	$ 44,657	$ 38,928
Work in process	6,269	7,146
Raw material, fuel and supplies	56,063	42,603
	$ 106,989	$ 88,677

Goodwill and Other Intangible Assets

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

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

	June 30, 2006			December 31, 2005		
(in thousands)	Gross carrying amount	Accumulated amortization	Net Carrying amount	Gross carrying amount	Accumulated amortization	Net Carryin amount
Amortized intangible assets:						
Covenants not to compete	$ 2,198	$ 1,637	$ 561	$ 2,338	$ 1,620	$ 718
Customer relationships	10,599	801	9,798	10,575	583	9,992
Other intangible assets including contracts	2,634	1,710	924	2,785	1,680	1,105
Total	$ 15,431	$ 4,148	$ 11,283	$ 15,698	$ 3,883	$ 11,815
Non-amortized intangible assets:						
Brand/trade name	$ 9,353	$	$ 9,353	$ 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 $557,000 for the six months ended June 30, 2006 compared to $543,000 for the six months ended June 30, 2005. The estimated annual amortization expense for these intangible assets for the next five years is: $1,070,000 for 2006, $872,000 for 2007, $727,000 for 2008, $636,000 for 2009 and

$507,000 for 2010.

Table of Contents

Comprehensive Income

(in thousands)	Three months ended June 30, 2006	Three months ended June 30, 2005	Six months ended June 30, 2006	Six months ended June 30, 2005
Net income	$ 11,394	$ 22,304	$ 26,354	$ 32,275
Other comprehensive income (net-of-tax)				
Minimum pension liability adjustment		(1,263)		(1,263)
Foreign currency translation gain (loss)	618	(176)	564	(259)
Unrealized (loss) gain on available-for-sale securities	(4)	16	(12)	(6)
Total other comprehensive income	614	(1,423)	552	(1,528)
Total comprehensive income	$ 12,008	$ 20,881	$ 26,906	$ 30,747

The foreign currency translation adjustments are associated with the Canadian operations of Idaho Pacific Holdings, Inc. (IPH). The unrealized losses on available-for-sale securities are associated with investments of the Company s captive insurance company.

New Accounting Standards

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

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

SFAS No. 156, *Accounting for Servicing of Financial Assets,* was issued in March 2006. This statement amends SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, with respect to the accounting for separately recognized servicing assets and servicing liabilities. This statement is effective as of the beginning of an entity s first fiscal year that begins after September 15, 2006. The Company does not currently have any servicing assets or servicing liabilities and does not anticipate that this statement will have any impact on its consolidated financial statements on the date the statement becomes effective.

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

Proposed Standard: In March 2006, the FASB issued an Exposure Draft, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans* that would amend SFAS No. 87, *Employers Accounting for Pensions*, SFAS No. 88, *Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions*, and SFAS No. 132 (Revised 2003), *Employers Disclosures about Pensions and Other Postretirement Benefits*. The FASB has received all comments and is expected to issue a new accounting standard in September 2006, to be effective for the Company s 2006 annual reporting period. Assuming the provisions of the new standard are consistent with current proposals, the standard will require, among other things, balance sheet recognition of the unrecognized portion of projected benefit obligations and of previously unrecognized actuarial gains and losses, prior service costs and transition obligations that have not yet been included in income, with an offsetting change in accumulated other comprehensive income (loss) in equity, net of the effect on deferred taxes. This initial stage of the FASB project is not expected to affect the measurement of the net periodic cost. The result of this proposed pronouncement will be the recognition on the Company s consolidated balance sheet of the over or under funded status of the benefit plans impacted by this statement. Had the proposed standard been applicable in 2005, the Company would have recorded a $30.6 million decrease in equity on its December 31, 2005 consolidated balance sheet.

Segment Information

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

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

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

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

Health services consists of businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide service maintenance, diagnostic imaging, positron emission tomography and nuclear medicine imaging, portable X-ray imaging and rental of diagnostic medical imaging equipment to various medical institutions located throughout the United States.

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

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

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

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information on continuing operations for the business segments for three and six month periods ended June 30, 2006 and 2005 and total assets by business segment as of June 30, 2006 and December 31, 2005 are presented in the following tables.

Operating Revenue

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2006	2005	2006	2005
Electric	$ 73,518	$ 74,150	$ 156,102	$ 147,633
Plastics	52,685	36,004	90,790	68,159
Manufacturing	81,631	67,858	149,888	123,387
Health services	32,833	31,324	64,909	59,122
Food ingredient processing	9,811	8,234	19,161	17,489
Other business operations	30,379	29,128	58,658	47,976
Intersegment eliminations	(953)	(899)	(1,797)	(1,883)
Total	$ 279,904	$ 245,799	$ 537,711	$ 461,883

Income (Loss) Before Income Taxes

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2006	2005	2006	2005
Electric	$ 5,281	$ 7,750	$ 19,976	$ 19,555
Plastics	8,149	3,950	15,805	8,357
Manufacturing	6,932	7,528	10,703	9,219
Health services	913	2,035	1,501	3,384
Food ingredient processing	(1,737)	410	(3,388)	1,609
Other business operations	(1,843)	(5,456)	(3,544)	(9,169)
Total	$ 17,695	$ 16,217	$ 41,053	$ 32,955

Table of Contents

Total Assets

(in thousands)	June 30, 2006	December 31, 2005
Electric	$ 657,129	$ 654,175
Plastics	94,548	76,573
Manufacturing	223,620	177,969
Health services	67,784	67,066
Food ingredient processing	98,861	96,023
Other business operations	90,559	95,989
Discontinued operations	600	13,701
Total	$ 1,233,101	$ 1,181,496

No single external customer accounts for 10% or more of the Company s revenues. Substantially all of the Company s long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Fort Erie, Ontario, Canada.
The following table presents the percent of consolidated sales revenue by country:

(in thousands)	Three months ended June 30, 2006	Three months ended June 30, 2005	Six months ended June 30, 2006	Six months ended June 30, 2005
United States of America	97.2%	98.1%	97.1%	98.0%
Canada	1.7%	1.1%	1.6%	1.1%
All other countries	1.1%	0.8%	1.3%	0.9%

Rate and Regulatory Matters

On December 29, 2000 the North Dakota Public Service Commission (NDPSC) approved a performance-based ratemaking plan that links allowed earnings in North Dakota to seven defined performance standards in the areas of price, electric service reliability, customer satisfaction and employee safety. The plan was in place through 2005. The electric utility s 2005 rate of return was within the allowable range defined in the plan, so no refunds or recoveries were ordered under the plan for 2005. The electric utility had applied to the NDPSC for a three year extension of the performance-based ratemaking plan with certain modifications. In May 2006, the NDPSC indicated that it did not wish to continue performance-based ratemaking at this time and the electric utility requested that its application be withdrawn.
In September 2004, a letter was provided to the Minnesota Public Utilities Commission (MPUC) summarizing issues and conclusions of an internal investigation completed by the Company related to claims of allegedly improper regulatory filings brought to the attention of the Company by certain individuals. On November 30, 2004 the electric utility filed a report with the MPUC responding to these claims. In 2005, the Energy Division of the Department of Commerce (DOC), the Residential Utilities Division of the Office of Attorney General and the claimants filed comments in response to the report, to which the Company filed reply comments. A hearing before the MPUC was held on February 28, 2006. As a result of the hearing, the electric utility agreed that within 90 days it would file a revised Regulatory Compliance Plan, an updated Corporate Cost Allocation Manual and documentation of the definitions of its chart of accounts. The electric utility filed these documents with the MPUC in the second quarter of 2006. The Company has received comments on its filings from the DOC and the claimants and expects to file reply comments in August 2006. The electric utility also agreed to file a general rate case in Minnesota on or before September 30, 2007.

Table of Contents

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

In December 2005 the MPUC issued an order denying the electric utility s request to allow recovery of certain Midwest Independent Transmission System Operator (MISO)-related costs through the fuel clause adjustment (FCA) in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. A $1.9 million reduction in revenue and a refund payable was recorded in December 2005 by the electric utility to reflect the refund obligation. On February 9, 2006 the MPUC decided to reconsider its December 2005 order. The Commission s final order was issued on February 24, 2006. In the order the MPUC ordered jurisdictional investor-owned utilities in the state to participate with the Minnesota Department of Commerce and other parties in a proceeding that will evaluate suitability of recovery of certain MISO Day 2 energy market costs through the FCA. The Minnesota utilities and other parties submitted a final report to the MPUC in July 2006. As of the date of this report on Form 10-Q, the MPUC had not reached a decision on the future treatment of certain MISO-related costs within the FCA or responded to the report submitted by the Minnesota utilities and other parties. In addition, the February 24, 2006 order eliminated the refund provision from the December 2005 order, and allowed that any MISO-related costs not recovered through the FCA may be deferred for a period of 36 months, with possible recovery through base rates in the electric utility s next general rate case which, for Otter Tail Power Company, is expected to be filed on or before September 30, 2007. As a result of this order, the electric utility recognized $1.9 million in revenue and reversed the refund payable in February 2006 and expects to recover all MISO-related costs through the FCA or to seek recovery, in a rate case, of any MISO-related costs not recoverable through the FCA.

On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time revenue sufficiency guarantee (RSG) charges that were not allocated to day-ahead virtual supply offers in accordance with MISO s Transmission and Energy Markets Tariff going back to the commencement of MISO Day 2 markets in April 2005. On May 17, 2006, the FERC issued a Notice of Extension of Time permitting the MISO to delay compliance with the directives contained in its April 2006 order, including the requirement to refund 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. The Company recorded $12.7 million in net revenues in 2005 and $1.0 million in net revenues in the first six months of 2006 related to virtual transactions. As of the date of this report on Form 10-Q, the Company is not able to assess what financial impact, if any, this order will have on its 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.

Table of Contents

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

(in thousands)	June 30, 2006	December 31, 2005
Regulatory assets:		
Deferred income taxes	$ 15,387	$ 16,724
Accrued cost-of-energy revenue	15,410	10,400
Reacquisition premiums	2,843	2,995
Deferred marked-to-market losses	1,486	1,423
Deferred conservation program costs	337	1,064
Accumulated ARO accretion/depreciation adjustment	256	209
Plant acquisition costs	174	196
Total regulatory assets	$ 35,893	$ 33,011
Regulatory liabilities:		
Accumulated reserve for estimated removal costs	$ 52,812	$ 52,582
Deferred income taxes	5,595	5,961
Deferred marked-to-market gains	2,000	2,925
Gain on sale of division office building	153	156
Total regulatory liabilities	$ 60,560	$ 61,624
Net regulatory liability position	$ 24,667	$ 28,613

The regulatory assets and liabilities related to deferred income taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes*. Reacquisition premiums included in *Unamortized debt expense and reacquisition premiums* are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 16.1 years. Deferred conservation program costs represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. Plant acquisition costs will be amortized over the next 3.9 years. Accrued cost-of-energy revenue included in *Accrued utility revenues* will be recovered over the next 13 months. All deferred marked-to-market gains and losses are related to forward purchases and sales of energy scheduled for delivery prior to January 2007. The accumulated reserve for estimated removal costs is reduced for actual removal costs incurred. The remaining regulatory assets and liabilities are being recovered from, or will be paid to, electric customers over the next 30 years.

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

Share-based Payments

On January 1, 2006 the Company adopted the accounting provisions of SFAS No. 123(R) (revised 2004), *Share-Based Payment,* on a modified prospective basis. SFAS No. 123(R) is a revision of SFAS No. 123, *Accounting for Stock-based Compensation*, and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*. Under SFAS No. 123(R), the Company records stock-based compensation as an expense on its income statement over the period earned based on the estimated fair value of the stock or options awarded on their grant date. The Company elected the modified prospective method of adopting SFAS No. 123(R), under which prior periods are not retroactively revised. The valuation provisions of SFAS No. 123(R) apply to awards granted after the effective date. Estimated stock-based compensation expense for awards granted prior to the effective date but that remain nonvested on the effective date will be recognized over the remaining service period using the compensation cost estimated for the SFAS No. 123 pro forma disclosures. Additionally, the adoption of SFAS No. 123(R) resulted in the reclassification of $798,000 in credits related to outstanding restricted share-based compensation from equity on the Company s consolidated balance sheet to a liability on January 1, 2006 because of income tax withholding provisions in the share-based award agreements. The adoption of SFAS 123(R) also resulted in the elimination of *Unearned compensation* (contra-equity account) from the equity section of the Company s consolidated balance sheet on January 1, 2006 by netting the account balance of $1,720,000 against *Premium on common shares.*

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

As of June 30, 2006, the total remaining unrecognized amount of compensation expense related to stock-based compensation was approximately $4.6 million (before income taxes), which will be amortized over a weighted-average period of 2.1 years.

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

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

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

The Purchase Plan allows employees through payroll withholding to purchase shares of the Company s common stock at a 15% discount from the average market price on the last day of a six month investment period. Under SFAS 123(R) the Company is required to record compensation expense related to the 15% discount which was not required under APB No. 25. Based on the participants current level of withholdings, the Company estimates that the 15% discount will amount to approximately $240,000 in 2006. The Company recorded $120,000 in compensation expense for the six month period ended June 30, 2006 related to the Purchase Plan. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company. The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive for the purpose of calculating diluted earnings per share during the investment period. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. The purchase of 27,543 common shares in the open market to satisfy the requirements of the Purchase Plan for the six month investment period ended June 30, 2006, was completed on August 1, 2006.

Stock Options Granted Under the Incentive Plan

Since the inception of the Incentive Plan in 1999, the Company has granted 2,041,500 options for the purchase of the Company s common stock. Of the options granted, 2,000,286 had vested or were forfeited and 41,214 were not vested as of June 30, 2006. The exercise price of the options granted has been the average market price of the Company s common stock on the grant date. These options were not compensatory under APB No. 25 accounting rules. Under SFAS No.123(R) accounting, compensation expense will be recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under SFAS No. 123(R) accounting, the fair value of the options granted will be recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the Incentive Plan has been based on the Black-Scholes option pricing model.

Under the modified prospective application of SFAS No.123(R) accounting requirements, the difference between the intrinsic value of nonvested options and the fair value of those options of $362,000 ($217,000 net-of-tax) on

Table of Contents

January 1, 2006 is being recognized on a straight-line basis as compensation expense over the remaining vesting period of the nonvested options, which, for nonvested options outstanding on January 1, 2006, will be from January 1, 2006 through April 30, 2007. Accordingly, the Company recorded compensation expense related to nonvested options issued under the Incentive Plan for the three and six month periods ended June 30, 2006 of $68,000 ($41,000 net-of-tax) and $136,000 ($82,000 net-of-tax), respectively.

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

(in thousands)	Three months ended June 30, 2005	Six months ended June 30, 2005
Net income		
As reported	$ 22,304	$ 32,275
Total stock-based employee compensation expense determined under fair value based method for all stock option awards net of related tax effects	(177)	(283)
Pro forma	$ 22,127	$ 31,992
Basic earnings per share:		
As reported	$ 0.76	$ 1.09
Pro forma	$ 0.75	$ 1.09
Diluted earnings per share:		
As reported	$ 0.76	$ 1.09
Pro forma	$ 0.75	$ 1.08

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

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

	Options	Weighted average exercise price	Aggregate intrinsic value (000 s)
Outstanding, January 1, 2006	1,237,164	$ 25.58	
Granted			
Exercised	52,415	$ 22.89	$ 371
Forfeited	25,423	$ 29.27	$ 27
Outstanding, June 30, 2006	1,159,326	$ 25.64	$ 3,020
Exercisable, June 30, 2006	1,118,112	$ 25.58	$ 3,008

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

The Company received cash of $1,200,000 for options exercised in the first half of 2006.

Table of Contents

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

	Options outstanding			Options exercisable	
Range of exercise prices	Outstanding as of 6/30/06	Weighted-average remaining contractual life (yrs)	Weighted-average exercise price	Exercisable as of 6/30/06	Weighted-average exercise price
$18.80-$21.94	279,213	3.3	$ 19.48	279,213	$ 19.48
$21.95-$25.07	62,850	8.8	$ 24.93	62,850	$ 24.93
$25.08-$28.21	595,263	5.6	$ 26.53	554,049	$ 26.47
$28.22-$31.34	222,000	5.8	$ 31.20	222,000	$ 31.20

Restricted Stock Granted to Directors

Under the Incentive Plan, restricted shares of the Company s common stock have been granted to members of the Company s Board of Directors as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the four-year vesting period of the restricted shares based on the market value of the Company s common stock on the grant date. Under the modified prospective application of SFAS No.123(R) accounting requirements, compensation expense related to nonvested restricted shares outstanding will be recorded based on the estimated fair value of the restricted shares on their grant dates. On April 9, 2006 the Compensation Committee of the Company s Board of Directors granted 19,800 shares of restricted stock to the directors under the Incentive Plan. The restricted shares vest ratably over a four-year vesting period. The amount of compensation expense recorded related to nonvested restricted shares granted to directors under SFAS No. 123(R) for the three and six month periods ended June 30, 2006 was $170,000 ($102,000 net-of-tax) and $241,000 ($145,000 net-of-tax), respectively. The amount of compensation expense recorded related to nonvested restricted shares granted to directors based on the intrinsic value of the restricted stock grants under APB No. 25 for the three and six month periods ended June 30, 2005 was $65,000 ($39,000 net-of-tax) and $119,000 ($71,000 net-of-tax), respectively. Nonvested restricted shares granted to directors are considered dilutive for the purpose of calculating diluted earnings per share but are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share.

Presented below is a summary of the status of directors restricted stock awards for the six months ended June 30, 2006:

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

Restricted Stock Granted to Employees

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

The amount of compensation expense recorded related to nonvested restricted shares granted to employees based on the estimated fair value of the restricted stock grants under SFAS No. 123(R) for the three and six month periods ended June 30, 2006 was $151,000 ($91,000 net-of-tax) and $442,000 ($265,000 net-of-tax), respectively. The amount of compensation expense recorded related to nonvested restricted shares granted to employees based on the intrinsic value of the restricted stock grants under APB No. 25 for the three and six month periods ended June 30, 2005 was $278,000 ($167,000 net-of-tax) and $549,000 ($329,000 net-of-tax), respectively. The equity account, *Unearned compensation,* was credited when compensation expense was recorded related to these shares under APB No. 25 accounting. Under SFAS 123(R) accounting, a current liability account is credited when compensation expense is recorded. Accumulated liabilities related to nonvested restricted shares issued to employees under this program will be reversed and credited to the *Premium on common shares* equity account as the shares vest. Nonvested restricted shares granted to employees are considered dilutive for the purpose of calculating diluted earnings per share but are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share.

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

	Shares		Weighted average reporting-date fair value
Nonvested, January 1, 2006	72,974	$	28.91
Granted			
Vested (fair value: $1,167,000)	41,308	$	28.25
Forfeited			
Nonvested, June 30, 2006	31,666	$	27.54

Restricted Stock Units Granted to Employees

On April 9, 2006, the Compensation Committee of the Company s Board of Directors granted 47,425 restricted stock units at a weighted average grant-date fair value of $25.41 per unit to key employees under the Incentive Plan payable in common shares. Each unit is automatically converted into one share of common stock on vesting. Vesting occurs from April 10, 2006 through April 8, 2010, with a weighted average contractual term of stock units outstanding as of June 30, 2006 of 3.1 years.

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

	Restricted stock units		Aggregate grant-date fair value (000 s)
Outstanding, January 1, 2006		$	
Granted	47,425		1,205
Converted	7,450		220

Forfeited	930		23
Outstanding, June 30, 2006	39,045	$	962

The amount of compensation expense recorded related to both vested and nonvested restricted stock units granted to employees in April 2006 based on the estimated fair value of the restricted stock unit grants under SFAS No.

Table of Contents

123(R) using a Monte Carlo valuation method for both the three and six month periods ended June 30, 2006 was $289,000 ($173,000 net-of-tax). The underlying shares related to nonvested restricted stock units granted to employees are considered dilutive for the purpose of calculating diluted earnings per share.

Stock Performance Awards granted to Executive Officers

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

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

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

Performance period	Maximum shares subject to award	Shares used to estimate expense	Amount of expense during the three months ended June 30,		Amount of expense during the six months ended June 30,	
			2006	**2005**	**2006**	**2005**
2004-2006	70,500	23,500	$ 47,000	$323,000	$ 94,000	$323,000
2005-2007	75,150	50,872	94,000	169,000	187,000	169,000
2006-2008	88,050	58,700	254,000		254,000	
Total	233,700	133,072	$395,000	$492,000	$535,000	$492,000

For the purpose of calculating diluted earnings per share, shares expected to be awarded are considered dilutive. Currently, the Company intends to purchase shares on the open market for stock performance awards earned.

Class B Stock Options and Class B Stock of Subsidiary

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

Common Shares and Earnings per Share

In the first six months of 2006 the Company issued 51,915 common shares for stock options exercised, 1,111 common shares and 19,800 restricted common shares for director s compensation and 7,450 common shares for restricted stock units that vested on issuance in April 2006. The Company retired 16,370 common shares for tax withholding purposes related to 39,825 restricted shares that vested in the first six months of 2006.

Basic earnings per common share are calculated by dividing earnings available for common shares by the average number of common shares outstanding during the period excluding any nonvested restricted shares outstanding during the period. Diluted earnings per common share are calculated by adjusting outstanding shares, assuming conversion of all potentially dilutive stock options and vesting of all nonvested restricted shares and restricted stock units outstanding and including contingently issuable shares related to outstanding stock performance awards. Stock options with exercise prices greater than the market price are excluded from the calculation of diluted earnings per common share.

Pension Plan and Other Postretirement Benefits

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

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2006	2005	2006	2005
Service cost benefit earned during the period	$ 1,210	$ 1,034	$ 2,420	$ 2,068
Interest cost on projected benefit obligation	2,544	2,448	5,088	4,896
Expected return on assets	(3,065)	(2,996)	(6,130)	(5,992)
Amortization of prior-service cost	186	240	372	481
Amortization of net actuarial loss	378		756	
Net periodic pension cost	$ 1,253	$ 726	$ 2,506	$ 1,453

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

Table of Contents

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

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2006	2005	2006	2005
Service cost benefit earned during the period	$ 107	$ 92	$ 213	$ 184
Interest cost on projected benefit obligation	325	316	651	632
Amortization of prior-service cost	18	18	36	36
Recognized net actuarial loss	118	104	236	208
Net periodic pension cost	$ 568	$ 530	$ 1,136	$ 1,060

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:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2006	2005	2006	2005
Service cost benefit earned during the period	$ 334	$ 311	$ 668	$ 622
Interest cost on projected benefit obligation	637	666	1,274	1,332
Amortization of transition obligation	187	187	374	374
Amortization of prior-service cost	(76)	(77)	(152)	(154)
Amortization of net actuarial loss	133	156	266	312
Effect of Medicare Part D expected subsidy	(293)	(201)	(586)	(402)
Net periodic postretirement benefit cost	$ 922	$ 1,042	$ 1,844	$ 2,084

Discontinued Operations

In June 2006, OTESCO, the Company s energy services company, sold its gas marketing operations for $0.5 million in cash. In 2005, the Company completed the sales of Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Net income from OTESCO s gas marketing operations classified under discontinued operations includes an after-tax gain on disposition of $0.3 million for the three and six month periods ended June 30, 2006 and 2005. Net income from MIS, SGS and CLC classified under discontinued operations includes an after-tax gain on the sale of MIS of $11.9 million for the three and six month periods ended June 30, 2005, an after-tax loss on the sale of SGS of $1.8 million (an estimated after-tax loss of $1.6 million recorded in the first quarter of 2005 plus an additional after-tax loss on disposition of $0.2 million recorded in the second quarter of 2005) and an estimated after-tax loss related to the sale of CLC of $0.2 million for the three and six month periods ended June 30, 2005. SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* requires that OTESCO s gas marketing operations, MIS, SGS and CLC be classified and reported separately as discontinued operations.

Table of Contents

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

(in thousands)	Three months ended June 30, 2006	Three months ended June 30, 2005				
	OTESCO Gas	OTESCO Gas	MIS	SGS	CLC	Total
Operating revenues	$ 7,263	$10,579	$ 1,729	$ 1,459	$2,067	$15,834
Income (loss) before income taxes	(120)	25	897	(1,179)	37	(220)
Gain (loss) on disposition pretax	560		19,025	(419)	(300)	18,306
Income tax expense (benefit)	183	10	7,467	(639)	(104)	6,734

(in thousands)	Six months ended June 30, 2006	Six months ended June 30, 2005				
	OTESCO Gas	OTESCO Gas	MIS	SGS	CLC	Total
Operating revenues	$ 28,234	$26,628	$ 3,773	$ 6,329	$3,772	$40,502
Income (loss) before income taxes	54	(18)	2,167	(1,563)	(19)	567
Gain (loss) on disposition pretax	560		19,025	(3,046)	(300)	15,679
Income tax expense (benefit)	252	(7)	7,975	(1,843)	(126)	5,999

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

(in thousands)	June 30, 2006			December 31, 2005			
	SGS	CLC	Total	OTESCO Gas	SGS	CLC	Total
Current assets	$ 406	$ 194	$ 600	$ 11,384	$ 857	$ 1,455	$ 13,696
Investments and other assets						5	5
Assets of discontinued operations	$ 406	$ 194	$ 600	$ 11,384	$ 857	$ 1,460	$ 13,701
Current liabilities	$ 195	$ 47	$ 242	$ 10,611	$ 328	$ 44	$ 10,983
Liabilities of discontinued operations	$ 195	$ 47	$ 242	$ 10,611	$ 328	$ 44	$ 10,983

The remaining assets and liabilities of SGS and CLC consist of accounts receivable, inventory at estimated fair market value and accounts payable that were not settled or disposed of as of June 30, 2006.

Table of Contents

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

RESULTS OF OPERATIONS

Comparison of the Three Months Ended June 30, 2006 and 2005

Consolidated operating revenues were $279.9 million for the three months ended June 30, 2006 compared with $245.8 million for the three months ended June 30, 2005. Operating income was $22.1 million for the three months ended June 30, 2006 compared with $20.8 million for the three months ended June 30, 2005. The Company recorded diluted earnings per share from continuing operations of $0.37 for the three months ended June 30, 2006 compared to $0.37 for the three months ended June 30, 2005 and total diluted earnings per share from continuing and discontinued operations of $0.38 for the three months ended June 30, 2006 compared to $0.76 for the three months ended June 30, 2005, which included $0.41 per share from a gain on the sale of Midwest Information Systems, Inc. (MIS).

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

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

	Three months ended June 30,	
(in thousands)	2006	2005
Operating revenues	$953	$899
Cost of goods sold	448	442
Other nonelectric expenses	505	457

Electric

	Three months ended June 30,			%
(in thousands)	2006	2005	Change	Change
Retail sales revenues	$ 61,805	$ 59,532	$ 2,273	3.8
Wholesale revenues	6,638	9,440	(2,802)	(29.7)
Net marked-to-market gain	1,260	999	261	26.1
Other revenues	3,815	4,179	(364)	(8.7)
Total operating revenues	$ 73,518	$ 74,150	$ (632)	(0.9)
Production fuel	11,456	10,549	907	8.6
Purchased power system use	17,664	19,904	(2,240)	(11.3)
Other operation and maintenance expenses	28,049	25,334	2,715	10.7
Depreciation and amortization	6,447	6,103	344	5.6
Property taxes	2,551	2,408	143	5.9
Operating income	$ 7,351	$ 9,852	$ (2,501)	(25.4)

The increase in retail electric revenue is due mainly to a $2.1 million increase in fuel clause adjustment (FCA) revenues related to recognizing $4.2 million of revenue for uncollected fuel and purchased power costs under an FCA true-up mechanism established by order of the Minnesota Public Utilities Commission (MPUC), offset by a $2.1 million reduction in FCA revenues billed and accrued related to lower costs for purchased power in the second quarter of 2006 compared to the second quarter of 2005. The Minnesota FCA true-up relates to costs incurred from July 2004 through June 2006 and will be recovered from Minnesota customers from August 2006 through July 2007. On a go-forward basis the electric utility will be on a yearly FCA true-up mechanism in Minnesota. The remaining $0.2 million increase in retail revenues resulted from a 2.5% increase in retail megawatt-hours (mwh) sold between the periods, reflecting increased mwh sales to residential, commercial and industrial customers. Industrial mwh sales increased 10.4% between the quarters mainly due to increased consumption by pipeline customers as higher oil prices have led to an increase in the volume of product being transported from Canada and the Williston basin. A 13.7% decrease in heating degree days was partially offset by a 21.0% increase in cooling degree days with the net effect of weather having no discernable impact on the variance in mwh sales between the periods.

Wholesale sales revenue from company-owned generation increased $2.1 million in the three months ended June 30, 2006 compared to the three months ended June 30, 2005 as a result of a 39.9% increase in mwhs sold combined with a 6.2% increase in the price per mwh sold between the periods. 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 revenue from energy trading activities including net mark-to-market gains on forward energy contracts were $1.5 million for the quarter ended June 30, 2006 compared with $6.1 million for the quarter ended June 30, 2005. The $4.6 million decrease in revenue from energy trading activities reflects a $3.3 million reduction in profits from purchased power resold and a $2.5 million reduction in net profits from virtual transactions, offset by a $0.9 million increase in profits from the purchase and sale of financial transmission rights and a $0.3 million increase in net mark-to-market gains on forward energy contracts. Profits from virtual transactions were $2.5 million in the second quarter of 2005 compared to only $24,000 in the second quarter of 2006 as the MISO market has matured and become more efficient and as a result of a reduction in virtual transactions due to uncertainties related to the status of Revenue Sufficiency Guarantee (RSG) charges in MISO s Transmission and Energy Markets Tariff.

The decrease in other electric operating revenues for the three months ended June 30, 2006 compared to the three months ended June 30, 2005 is mainly due to a reduction in MISO tariff revenue.

The increase in fuel costs for the three months ended June 30, 2006 compared with the three months ended June 30, 2005 reflects a 1.8% increase in mwhs generated combined with a 6.7% increase in the cost of fuel per mwh generated. Generation used for wholesale electric sales increased 39.9% while generation for retail sales decreased 5.5% between the periods. The increase in fuel costs per mwh generated is a function of the mix of available generation resources. In the second quarter of 2006, our lowest cost base-load plant, Coyote Station, was off-line for five weeks for scheduled maintenance. In the second quarter of 2005, the higher-cost Big Stone Plant was shutdown for seven weeks for scheduled maintenance. Big Stone Plant s generation increased 78.2% between the quarters while Coyote s generation was down 47.5%. Increases in coal and coal transportation costs contributed to a 6.1% increase in the cost of fuel per mwh generated at Hoot Lake plant. Much of the increase in coal and coal transportation costs is directly related to higher diesel fuel prices. Approximately 90% of the fuel cost increases associated with generation to serve retail electric customers is subject to recovery through the fuel cost recovery component of retail rates.

The decrease in purchased power system use (to serve retail customers) is due to a 22.4% decrease in the cost per mwh purchased partially offset by a 14.3% increase in mwhs purchased. Advance purchases of electricity in anticipation of coal supply constraints at Big Stone and Hoot Lake plants in the second quarter of 2006 contributed to the increase in mwh purchases for system use.

Table of Contents

The increase in other operation and maintenance expenses for the three months ended June 30, 2006 compared with the three months ended June 30, 2005 includes $0.8 million for contracted services related to the five-week scheduled maintenance shutdown at Coyote Station in the second quarter of 2006, a reduction of $0.7 million in cost reimbursements related to the proposed new generating unit at the Big Stone Plant site, a $0.6 million increase in employee benefit expenses and $0.3 million increase in pollution control expenditures for bag replacement and service costs on the advanced hybrid particulate collector at Big Stone Plant.

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

Plastics

(in thousands)	Three months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 52,685	$ 36,004	$ 16,681	46.3
Cost of goods sold	41,442	29,664	11,778	39.7
Operating expenses	2,058	1,460	598	41.0
Depreciation and amortization	678	628	50	8.0
Operating income	$ 8,507	$ 4,252	$ 4,255	100.1

Operating revenues for the plastics segment increased between the periods as result of a 19.0% increase in pounds of polyvinyl chloride (PVC) pipe sold combined with a 20.4% increase in the price per pound of PVC pipe sold. The increase in revenue reflects high demand from distributors and the effect of a 10.9% increase in resin costs per pound of PVC pipe shipped between the periods. The increase in cost of goods sold is a result of the increase in pounds of pipe sold combined with higher resin costs. The increase in plastics segment operating expenses between the quarters is directly related to the increases in sales and operating income. The increase in depreciation and amortization expense is the result of $3.6 million in capital expenditures in 2005, mainly for production equipment.

Manufacturing

(in thousands)	Three months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 81,631	$ 67,858	$ 13,773	20.3
Cost of goods sold	63,256	51,519	11,737	22.8
Operating expenses	6,890	5,332	1,558	29.2
Depreciation and amortization	2,710	2,345	365	15.6
Operating income	$ 8,775	$ 8,662	$ 113	1.3

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

Revenues at DMI Industries, Inc. (DMI) increased $12.7 million, of which $3.8 million is related to the new Ft. Erie plant, as a result of an increase in production and sales activity due in part to plant additions and continued improvements in productivity and capacity utilization.

Revenues at T.O. Plastics increased $0.8 million between the quarters as a result of an 11.1% increase in revenue per unit sold directly related to increased material costs, partially offset by a 2.1% reduction in unit sales.

Revenues at ShoreMaster increased $0.7 million between the quarters mainly due to the acquisition of Southeast Floating Docks on May 31, 2005.

Revenues at BTD Manufacturing, Inc. (BTD) decreased $0.4 million mainly as a result of a 4.2% decrease in units sold between the quarters.

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

DMI s cost of goods sold increased $11.3 million between the quarters, including $7.7 million in material cost increases. The increase in cost of goods sold is directly related to the increase in DMI s production and sales activity.

Cost of goods sold at T.O. Plastics increased $0.8 million, mainly due to $0.7 million in material cost increases between the quarters.

Cost of goods sold at ShoreMaster increased $0.7 million between the quarters as a result of increases in aluminum, subcontractor and other costs, mainly related to the acquisition of Southeast Floating Docks in May 2005.

Cost of goods sold at BTD decreased $1.1 million between the quarters mainly due to a decrease in material costs related to the decrease in unit sales between the quarters.

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

Operating expenses at DMI increased $0.7 million as a result of increases in labor, travel and professional service expenses mainly related to start-up costs at the Ft. Erie, plant.

T.O. Plastics operating expenses increased $0.3 million, which reflects a $0.2 reduction in gains on sales of fixed assets related to fixed asset sales in the second quarter of 2005.

ShoreMaster s operating expenses increased $0.3 million as a result of a $0.2 million increase in bad debt expense and an increase in labor costs between the quarters.

An increase in incentive accruals contributed to a $0.3 million increase in BTD s operating expenses between the quarters.

Depreciation expense increased between the quarters as a result of the Southeast Floating Docks acquisition and capital additions at all four manufacturing companies in 2005.

Health Services

(in thousands)	Three months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 32,833	$ 31,324	$ 1,509	4.8
Cost of goods sold	25,225	22,795	2,430	10.7
Operating expenses	5,568	5,272	296	5.6
Depreciation and amortization	879	1,010	(131)	(13.0)
Operating income	$ 1,161	$ 2,247	$ (1,086)	(48.3)

The increase in health services operating revenues for the three months ended June 30, 2006 compared with the three months ended June 30, 2005 reflects a $0.8 million increase in revenues from rentals and interim installations of scanning equipment along with providing technical support services for those rental and interim installations, a $0.5 million increase in scanning services revenue and $0.2 million reduction in returns and allowances. A 12.1% increase in the revenue per scan was partially offset by a 7.9% decrease in the number of scans performed between the quarters. Revenues from sales and servicing of equipment and sales of supplies and accessories were unchanged between the periods. The increase in health services revenue was more than offset by the increase in health services cost of goods sold, mainly as a result of increases in unit rental costs and sublease costs. Health services general and administrative expenses were also up by $0.3 million mainly due to higher insurance, education and licensing expenses. The decrease in depreciation and amortization expense is the result of certain assets reaching the ends of their depreciable lives. When these assets are replaced, they are generally replaced with assets leased under operating leases.

Food Ingredient Processing

(in thousands)	Three months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 9,811	$ 8,234	$ 1,577	19.2
Cost of goods sold	9,691	6,421	3,270	50.9
Operating expenses	790	536	254	47.4
Depreciation and amortization	948	821	127	15.5
Operating (loss) income	$ (1,618)	$ 456	$ (2,074)	(454.8)

The increase in food ingredient processing revenues reflects a 3.9% increase in pounds sold combined with a 14.7% increase in sales price per pound of product sold between the periods. The food ingredient processing segment has been negatively impacted by raw potato supply shortages in Idaho and Prince Edward Island. Higher than expected raw potato costs related to the supply shortages have resulted in operating inefficiencies and a 45.2% increase in the cost per pound of product sold. The increase in operating expenses is due to an increase in contracted service expenses between the quarters.

Table of Contents

Other Business Operations

(in thousands)	Three months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 30,379	$ 29,128	$ 1,251	4.3
Cost of goods sold	17,197	19,645	(2,448)	(12.5)
Operating expenses	14,505	13,485	1,020	7.6
Depreciation and amortization	717	646	71	11.0
Operating loss	$ (2,040)	$ (4,648)	$ 2,608	(56.1)

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

Revenues at Foley Company increased $3.9 million in the second quarter of 2006 compared to the second quarter of 2005 due to an increase in the volume of work performed between the periods.

Revenues at E.W. Wylie Corporation (Wylie) increased $1.9 million between the quarters mainly due to a 13.0% net increase in miles driven by owner-operated and company-operated trucks. Miles driven by owner-operated trucks increased 62.5% while miles driven by company-operated trucks decreased 6.5% between the quarters. Wylie s increased revenues also reflect increased fuel costs recovered through fuel surcharges between the quarters.

Revenues at Midwest Construction Services, Inc. (MCS) decreased $4.5 million between the quarters as a result of a delay on the start-up of several wind projects. Selected projects have been delayed nationwide due to Federal Aviation Administration actions related to possible radar issues.

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

Foley Company s cost of goods sold increased $2.7 million mainly in the areas of subcontractor and labor costs as a result of increased volume of work performed between the periods.

Cost of goods sold at MCS decreased $5.1 million mainly due to a reduction in material and labor costs between the quarters.

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

Wylie s revenue increase was mostly offset by a $1.8 million increase in operating expenses, mainly contractor costs related to the increase in miles driven by owner-operated trucks between the periods.

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

Operating expenses in this segment decreased $1.2 million mainly due to a decrease in self-insurance costs related to health insurance.

Table of Contents

Income Taxes Continuing Operations

The $1.3 million (24.6%) increase in income taxes continuing operations between the quarters is primarily the result of a $1.5 million (9.1%) increase in income from continuing operations before income taxes for the three months ended June 30, 2006 compared with the three months ended June 30, 2005. The effective tax rate for continuing operations for the three months ended June 30, 2006 was 37.1% compared to 32.5% for the three months ended June 30, 2005. The increase in the effective tax rate is related to a change in estimate in the reversal of regulatory deferred tax liabilities at the electric utility, a $0.5 million write-down of deferred tax assets in the second quarter of 2006 related to the expected expiration of operating loss carryforwards at the end of 2006 at IPH s Canadian operations and an increase in taxable income relative to a fixed level of tax credits between the quarters.

Discontinued Operations

Discontinued operations includes the operating results of the gas marketing operation of OTESCO, the Company s energy services company, for the three month periods ended June 30, 2006 and 2005 and of Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC) for the three months ended June 30, 2005. In June 2006, OTESCO sold its gas marketing operations for $0.5 million in cash. The Company completed the sales of MIS and SGS in the second quarter of 2005 and the sale of CLC was pending as of June 30, 2005. Discontinued operations include net (loss) income from discontinued operations for the three months ended June 30, 2006 and 2005 and net after-tax gains and losses on the disposition of discontinued operations during the three months ended June 30, 2006 and 2005 as shown in the following table:

(in thousands)	Three months ended June 30, 2006 OTESCO Gas	Three months ended June 30, 2005 OTESCO Gas	MIS	SGS	CLC	Total
(Loss) Income before income taxes	$ (120)	$ 25	$ 897	$ (1,179)	$ 37	$ (220)
Gain (loss) on disposition pretax	560		19,025	(419)	(300)	18,306
Income tax expense (benefit)	183	10	7,467	(639)	(104)	6,734
Net income (loss)	$ 257	$ 15	$ 12,455	$ (959)	$ (159)	$ 11,352

28

Table of Contents

Comparison of the Six Months Ended June 30, 2006 and 2005

Consolidated operating revenues were $537.7 million for the six months ended June 30, 2006 compared with $461.9 million for the six months ended June 30, 2005. Operating income was $49.5 million for the six months ended June 30, 2006 compared with $41.9 million for the six months ended June 30, 2005. The Company recorded diluted earnings per share from continuing operations of $0.86 for the six months ended June 30, 2006 compared to $0.74 for the six months ended June 30, 2005 and total diluted earnings per share from continuing and discontinued operations of $0.87 for the six months ended June 30, 2006 compared to $1.09 for the six months ended June 30, 2005, which included $0.41 per share from a gain on the sale of MIS and a reduction of $0.06 per share from a loss on the sale of SGS.

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

	Six months ended June 30,	
(in thousands)	2006	2005
Operating revenues	$1,797	$1,883
Cost of goods sold	768	953
Other nonelectric expenses	1,029	930

Electric

	Six months ended June 30,			%
(in thousands)	2006	2005	Change	Change
Retail sales revenues	$ 135,164	$ 122,847	$ 12,317	10.0
Wholesale revenues	12,296	14,357	(2,061)	(14.4)
Net marked-to-market gain	351	1,103	(752)	(68.2)
Other revenues	8,291	9,326	(1,035)	(11.1)
Total operating revenues	$ 156,102	$ 147,633	$ 8,469	5.7
Production fuel	26,262	25,726	536	2.1
Purchased power system use	36,400	31,442	4,958	15.8
Other operation and maintenance expenses	51,456	49,252	2,204	4.5
Depreciation and amortization	12,804	12,203	601	4.9
Property taxes	5,169	5,081	88	1.7
Operating income	$ 24,011	$ 23,929	$ 82	0.3

The increase in retail electric revenue is due mainly to an $11.6 million increase in FCA revenues related to increases in fuel and purchased power costs for system use, but also includes $4.2 million of revenue for uncollected fuel and purchased power costs under a FCA true-up mechanism established by order of the MPUC and $1.9 million related to the reversal of the refund provision established in December 2005 relating to MISO costs. The Minnesota FCA true-up relates to costs incurred from July 2004 through June 2006 and will be recovered from Minnesota customers from August 2006 through July 2007. On a go-forward basis the electric utility will be on a yearly FCA true-up mechanism in Minnesota. In December 2005, the MPUC issued an order denying recovery of certain MISO related costs through the FCA in Minnesota retail rates and requiring a refund of amounts previously collected. In

February 2006 the MPUC reconsidered its order and eliminated the refund requirement. The remaining $0.7 million increase in retail revenues resulted from a 1.8% increase in retail mwhs sold between the periods, reflecting increased sales to industrial customers partially offset by decreased sales to residential customers. Mwh sales to commercial customers increased by only 0.4% between the periods. Industrial mwh sales increased 17.9% between the periods mainly due to increased consumption by pipeline customers as higher oil prices have led to an increase in the volume of product being transported from Canada and the Williston basin. A 10.0% decrease in heating degree days was partially offset by a 21.0% increase in cooling degree days with the net effect of weather having no discernable impact on the variance in mwh sales between the periods.

Wholesale sales revenue from company-owned generation increased $3.3 million in the six months ended June 30, 2006 compared to the six months ended June 30, 2005 as a result of a 26.7% increase in mwhs sold combined with a 9.4% increase in the price per mwh sold between the periods. Advance purchases of electricity in anticipation of normal winter weather resulted in increased wholesale electric sales in January 2006 due to unseasonably mild weather. Wholesale sales from company-owned generation were curtailed in February and March 2006 as generation levels were restricted due to coal supply constraints at Big Stone and Hoot Lake plants. Advance purchases of electricity in anticipation of continuing coal supply constraints in the second quarter of 2006 freed up more generation for wholesale sales when coal supplies improved in May 2006. Net revenue from energy trading activities including net mark-to-market gains on forward energy contracts were $0.9 million for the six months ended June 30, 2006 compared with $7.0 million for the six months ended June 30, 2005. The $6.1 million decrease in revenue from energy trading activities reflects a $4.6 million reduction in profits from purchased power resold, a $1.5 million reduction in net profits from virtual transactions and a $0.8 million decrease in net mark-to-market gains on forward energy contracts, offset by a $0.8 increase in profits from the purchase and sale of financial transmission rights. Profits from virtual transactions were $2.5 million in the first six months of 2005 compared to $1.0 million in the first six months of 2006 as the MISO market has matured and become more efficient and as a result of a reduction in virtual transactions due to uncertainties related to the status of RSG charges in MISO s Transmission and Energy Markets Tariff. Of the $2.9 million in net mark-to-market gains recognized on open forward energy contracts at December 31, 2005, $2.3 million was realized and $0.5 million was reversed in the first six months of 2006 as market prices on forward electric contracts declined in response to decreased demand for electricity due, in part, to regional winter weather that was milder than expected.

The decrease in other electric operating revenues for the six months ended June 30, 2006 compared to the six months ended June 30, 2005 is mainly due to a reduction in transmission services revenue related to the initiation of the MISO Day 2 market in April 2005. Certain revenues that were billed separately prior to inception of the MISO Day 2 market are now included in revenue from wholesale energy sales or reflected as a reduction in purchased power costs.

The increase in fuel costs for the six months ended June 30, 2006 compared with the six months ended June 30, 2005 reflects a 5.8% increase in the cost of fuel per mwh generated partially offset by a 3.5% reduction in mwhs generated. Generation used for wholesale electric sales increased 26.7% while generation for retail sales decreased 8.2% between the periods. Fuel costs per mwh increased at all three of our coal-fired generating plants as a result of increases in coal and coal transportation costs between the periods. Much of the increase in coal and coal transportation costs is directly related to higher diesel fuel prices. The mix of available generation resources in the first six months of 2006 compared to the first six months of 2005 was also a contributing factor to the increase in the cost of fuel per mwh generated. Big Stone Plant s generation increased 12.3% between the periods while Coyote Station s generation was down 21.1%. In the second quarter of 2006, Coyote Station, our lowest cost base-load plant, was off-line for five weeks for scheduled maintenance. In the second quarter of 2005, the higher-cost Big Stone Plant was shutdown for seven weeks for scheduled maintenance. Approximately 90% of the fuel cost increases associated with generation to serve retail electric customers is subject to recovery through the fuel cost recovery component of retail rates.

The increase in purchased power system use (to serve retail customers) is due to a 16.8% increase in mwhs purchased only slightly offset by a 0.8% reduction in the cost per mwh purchased. An increase in mwh purchases for

Table of Contents

system use was necessary to make up for reductions in generation levels caused by delayed coal shipments to Big Stone and Hoot Lake Plants in February and March of 2006. Additional advance purchases of electricity in anticipation of continued coal supply constraints in the second quarter of 2006 also contributed to the increase in mwh purchases for system use.

The increase in other operation and maintenance expenses for the six months ended June 30, 2006 compared with the six months ended June 30, 2005 includes $0.8 million for contracted services related to the five-week scheduled maintenance shutdown at Coyote Station in the second quarter of 2006, $0.6 million in increased costs related to contracted construction work performed for other area utilities, $0.3 million for major repairs to our combustion turbine at Lake Preston, a $0.3 million increase in pollution control expenditures for bag replacement and service costs on the advanced hybrid particulate collector at Big Stone Plant and $0.2 million in higher fuel costs for fleet vehicles.

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

Plastics

(in thousands)	Six months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 90,790	$ 68,159	$ 22,631	33.2
Cost of goods sold	69,622	55,081	14,541	26.4
Operating expenses	3,506	2,969	537	18.1
Depreciation and amortization	1,408	1,219	189	15.5
Operating income	$ 16,254	$ 8,890	$ 7,364	82.8

Operating revenues for the plastics segment increased between the periods as result of a 2.7% increase in pounds of PVC pipe sold and a 25.2% increase in the price per pound of PVC pipe sold. The increase in revenue reflects high demand from distributors and the effect of a 16.7% increase in resin costs per pound of PVC pipe shipped between the periods. The increase in cost of goods sold is a result of higher resin costs in combination with the increase in pounds of pipe sold. The increase in plastics segment operating expenses between the periods is mainly due to increases directly related to the increases in sales and operating income. The increase in depreciation and amortization expense is the result of $3.6 million in capital expenditures in 2005, mainly for production equipment.

Manufacturing

(in thousands)	Six months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 149,888	$ 123,387	$ 26,501	21.5
Cost of goods sold	117,655	96,878	20,777	21.4
Operating expenses	13,105	10,754	2,351	21.9
Depreciation and amortization	5,279	4,550	729	16.0
Operating income	$ 13,849	$ 11,205	$ 2,644	23.6

Table of Contents

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

Revenues at DMI increased $23.1 million as a result of increases in production and sales activity due in part to plant additions, including initial operations at the Ft. Erie facilities, and continued improvements in productivity and capacity utilization.

Revenues at ShoreMaster increased $2.2 million between the periods mainly due to the acquisition of Southeast Floating Docks in May 2005.

Revenues at T.O. Plastics increased $1.2 million between the periods as a result of a 2.8% increase in unit sales combined with a 4.3% increase in revenue per unit sold.

Revenues at BTD were essentially unchanged between the periods.

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

DMI s cost of goods sold increased $19.3 million between the periods, including increases of $14.1 million in material costs, $3.5 million in labor and benefit costs and $1.6 in tools and supplies expenditures. The increase in cost of goods sold is directly related to the increase in DMI s production and sales activity and start up costs at its Ft. Erie facilities.

Cost of goods sold at ShoreMaster increased $1.5 million between the periods as a result of increases in labor and other direct costs, mainly related to the acquisition of Southeast Floating Docks in May 2005.

Cost of goods sold at T.O. Plastics increased $1.5 million, reflecting $1.2 million in material cost increases and $0.3 million in increased labor and benefit costs between the periods.

Cost of goods sold at BTD decreased $1.7 million between the periods due to a $0.9 million decrease in material costs related to a 6.5% decrease in unit sales between the periods and a $0.8 million decrease in labor costs. The decrease in production labor costs is related to a reduction in the number of production employees and a decrease in overtime pay between the periods. Productivity gains at BTD were achieved through efforts to better utilize and allocate available labor resources.

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

Operating expenses at DMI increased $1.3 million as a result of increases in labor, professional services and maintenance expenses mainly related to start-up costs at the Ft. Erie plant.

ShoreMaster s operating expenses increased $0.5 million as a result of increases in wage and benefit expenses mainly related to the May 2005 acquisition of Southeast Floating Docks.

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

T.O. Plastics operating expenses increased $0.2 million due to a reduction in gains on sales of fixed assets related to fixed asset sales in the second quarter of 2005.

Depreciation expense increased between the periods as a result of the Southeast Floating Docks acquisition and capital additions at all four manufacturing companies in 2005.

Table of Contents

Health Services

(in thousands)	Six months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 64,909	$ 59,122	$ 5,787	9.8
Cost of goods sold	50,047	43,087	6,960	16.2
Operating expenses	11,082	10,185	897	8.8
Depreciation and amortization	1,836	2,077	(241)	(11.6)
Operating income	$ 1,944	$ 3,773	$ (1,829)	(48.5)

The increase in health services operating revenues for the six months ended June 30, 2006 compared with the six months ended June 30, 2005 reflects a $5.2 million increase in imaging revenues combined with a $0.6 million increase in revenues from sales and servicing of diagnostic imaging equipment. On the imaging side of the business, $3.2 million of the $5.2 million increase in revenue came from imaging services where the revenue per scan increased 15.0% between the periods while the number of scans completed decreased 4.8%. Revenues from rentals and interim installations of scanning equipment along with providing technical support services for those rental and interim installations increased $2.3 million between the periods. The increase in health services revenue was more than offset by the increase in health services cost of goods sold, reflecting increased equipment rental and labor costs related to an increase in imaging and interim services activity and maintenance and sublease costs related to units that were out of service in the first six months of 2006. The increase in operating expenses is mainly due to higher labor and benefit costs and increases in travel, licensing and insurance expenses. The decrease in depreciation and amortization expense is the result of certain assets reaching the ends of their depreciable lives. When these assets are replaced, they are generally replaced with assets leased under operating leases.

Food Ingredient Processing

(in thousands)	Six months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 19,161	$ 17,489	$ 1,672	9.6
Cost of goods sold	19,010	13,106	5,904	45.0
Operating expenses	1,475	1,079	396	36.7
Depreciation and amortization	1,866	1,646	220	13.4
Operating (loss) income	$ (3,190)	$ 1,658	$ (4,848)	(292.4)

The increase in food ingredient processing revenues reflects a 10.2% increase in sales price per pound of product sold slightly offset by a 0.6% decrease in pounds sold between the periods. The food ingredient processing segment has been negatively impacted by raw potato supply shortages in Idaho and Prince Edward Island. Higher than expected raw product costs related to the supply shortages have resulted in operating inefficiencies and a 45.9% increase in the cost per pound of product sold. The increase in operating expenses is due to an increase in contracted service expenses between the periods.

Other Business Operations

(in thousands)	Six months ended June 30, 2006	2005	Change	% Change
Operating revenues	$ 58,658	$ 47,976	$ 10,682	22.3
Cost of goods sold	33,191	30,033	3,158	10.5
Operating expenses	27,415	24,227	3,188	13.2
Depreciation and amortization	1,410	1,243	167	13.4
Operating loss	$ (3,358)	$ (7,527)	$ 4,169	(55.4)

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

Revenues at Foley Company increased $11.1 million in the first six months of 2006 compared to the first six months of 2005 due to an increase in the volume of work performed between the periods.

Revenues at Wylie increased $2.7 million between the periods mainly due to a 7.8% net increase in miles driven by owner-operated and company-operated trucks. Miles driven by owner-operated trucks increased 55.9% while miles driven by company-operated trucks decreased 9.8% between the periods. Wylie s increased revenues also reflect increased fuel costs recovered through fuel surcharges between the periods.

Revenues at MCS decreased $3.1 million between the periods as a result of a delay on the start-up of several wind projects. Selected projects have been delayed nationwide due to Federal Aviation Administration actions related to possible radar issues.

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

Foley Company s cost of goods sold increased $9.0 million mainly in the areas of materials, subcontractor costs and labor as a result of an increase in the volume of work performed between the periods.

Cost of goods sold at MCS decreased $5.8 million mainly due to a reduction in material and labor costs between the periods related to a reduction in job activity.

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

Wylie s revenue increase was entirely offset by a $2.7 million increase in operating expenses, including $2.2 million in contractor costs related to the increase in miles driven by owner-operated trucks between the periods, $0.3 million in increased insurance costs and $0.2 million in increased fuel costs.

Foley Company s operating expenses increased $0.5 million between the periods, mainly as a result of increases in compensation costs.

MCS operating expenses increased $0.4 million between the periods, mainly due to increases in salary and benefit expenses.

Operating expenses in this segment decreased $0.4 million mainly due to a decrease in self-insurance costs related to health insurance.

Table of Contents

Income Taxes Continuing Operations

The $4.1 million (37.8%) increase in income taxes continuing operations between the periods is primarily the result of an $8.1 million (24.6%) increase in income from continuing operations before income taxes for the six months ended June 30, 2006 compared with the six months ended June 30, 2005. The effective tax rate for continuing operations for the six months ended June 30, 2006 was 36.7% compared to 33.2% for the six months ended June 30, 2005. The increase in the effective tax rate is related to a change in estimate in the reversal of regulatory deferred tax liabilities at the electric utility, a $0.5 million write-down of deferred tax assets in the second quarter of 2006 related to the expected expiration of operating loss carryforwards at the end of 2006 at IPH s Canadian operations and an increase in taxable income relative to a fixed level of tax credits between the periods.

Discontinued Operations

Discontinued operations includes the operating results of the gas marketing operation of OTESCO, the Company s energy services company, for the six month periods ended June 30, 2006 and 2005 and of MIS, SGS and CLC for the six month period ended June 30, 2005. In June 2006, OTESCO sold its gas marketing operations for $0.5 million in cash. The Company completed the sales of MIS and SGS in the second quarter of 2005 and the sale of CLC was pending as of June 30, 2005. Discontinued operations include net income (loss) from discontinued operations for the six month periods ended June 30, 2006 and 2005 and net after-tax gains and losses on the disposition of discontinued operations in the six month periods ended June 30, 2006 and 2005 as shown in the following table:

	Six months ended June 30, 2006	Six months ended June 30, 2005				
(in thousands)	OTESCO Gas	OTESCO Gas	MIS	SGS	CLC	Total
Income (loss) before income taxes	$ 54	$ (18)	$ 2,167	$ (1,563)	$ (19)	$ 567
Gain (loss) on disposition pretax	560		19,025	(3,046)	(300)	15,679
Income tax expense (benefit)	252	(7)	7,975	(1,843)	(126)	5,999
Net income (loss)	$ 362	$ (11)	$ 13,217	$ (2,766)	$ (193)	$ 10,247

2006 OUTLOOK

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

We are revising our guidance upward to be in the range of $1.55 to $1.75 of diluted earnings per share from continuing operations from $1.50 to $1.70. Items contributing to the current earnings guidance for 2006 are as follows:

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

- We expect plastics segment earnings for 2006 to be similar to 2005 levels due to the strong performance in the first and second quarters of 2006 and continued high prices for PVC resin.

Table of Contents

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

The health services segment is expected to have lower earnings than original 2006 guidance due to the lower than expected results in the first half of 2006.

We expect to record a net loss in the range of $1.6 million to $3.4 million from our food ingredient processing business in 2006. This is a reduction from the break-even expectation announced in our first quarter earnings release. This change in guidance is due to lower than expected results in the first half of 2006 and the continuing shortage of raw potato supplies, which are expected to continue through most of 2006.

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

FINANCIAL POSITION

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

During the first six months of 2006 the Company issued 52,415 common shares for stock options exercised and 1,111 common shares for director s compensation and retired 16,370 common shares for tax withholding purposes related to restricted shares that vested in March and April 2006.

We have the ability to issue up to $256 million of common stock, preferred stock, debt and certain other securities from time to time under our universal shelf registration statement filed with the Securities and Exchange Commission. On April 26, 2006 we renewed our line of credit with U.S. Bank National Association, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, Harris Nesbitt Financing, Inc., Keybank National Association, Union Bank of California, N.A., Bank of America, N.A., Bank Hapoalim B.M., and Bank of the West and increased the amount available under the line from $100 million to $150 million. The renewed agreement expires on April 26, 2009. The terms of the renewed line of credit are essentially the same as those in place prior to the renewal. However, outstanding letters of credit issued by the Company can reduce the amount available for borrowing under the line by up to $30 million and we can increase our commitments under the renewed line of

Table of Contents

credit up to $200 million. Borrowings under the line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of our senior unsecured debt. This line is an unsecured revolving credit facility available to support borrowings of our nonelectric operations. We anticipate that the electric utility s cash requirements through April 2009 will be provided for by cash flows from electric utility operations or through other borrowing arrangements. Our obligations under this line of credit are guaranteed by a 100%-owned subsidiary that owns substantially all of our nonelectric companies. As of June 30, 2006, $59.0 million of the $150 million line of credit was in use and $18.3 million was restricted from use to cover outstanding letters of credit.

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

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

Our current securities ratings are:

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

Our disclosure of these securities ratings is not a recommendation to buy, sell or hold our securities. Downgrades in these securities ratings could adversely affect our company. Further downgrades could increase borrowing costs resulting in possible reductions to net income in future periods and increase the risk of default on our debt obligations.

Cash used in operating activities for continuing operations was $2.3 million for the six months ended June 30, 2006 compared with cash provided by operating activities from continuing operations of $2.8 million for the six months ended June 30, 2005. The $5.1 million increase in cash used for operating activities by continuing operations reflects an increase in cash used for working capital items of $13.1 million between the periods, offset by a $4.0 million increase in net income from continuing operations plus increases in non-cash items included in net income of $2.7 million related to mark-to-market changes in derivate energy contracts and $1.7 million in depreciation expense between the quarters. Cash used for working capital items during the six months ended June 30, 2006 was $55.8 million compared with $42.7 million used for working capital items during the six months ended June 30, 2005. Major uses of funds for working capital items in the first six months of 2006 were an increase in other current assets of $25.6 million, an increase in inventories of $18.0 million, an increase in receivables of $14.8 million and a decrease in payables and other current liabilities of $7.4 million, mainly related to a normal seasonal reduction in accounts payable from December to June at the electric utility, offset by a $10.1 million increase in interest and income taxes payable, mainly due to the timing of estimated tax payments.

Table of Contents

The increase in other current assets includes an increase of $23.0 million in costs in excess of billings at DMI mainly related to wind tower production to fill a large order that extends into 2007. While a number of units in this order have been completed, the terms of the contract specify that the customer, who has a strong senior unsecured debt rating, will not be billed until the units are shipped. The increase in other current assets also includes a $1.8 million increase in prepaid expenses at the health services companies.

DMI s inventories increased $8.1 million in the first six months of 2006 as a result of increases in raw material costs and in response to increased demand for wind towers. Our food ingredient processing companies inventories increased $3.4 million mainly as a result of increases in raw material costs (prices paid for process-grade potatoes), and related to a seasonal build-up of finished goods inventory as the processing season nears its end. Our construction companies inventories increased $2.8 million mostly related to a build up of electronic surveillance and security products at MCS. Inventories at the electric utility increased $3.0 million, of which $1.4 million relates to a build up of coal stockpiles at Big Stone and Hoot Lake plants since year-end 2005 and $1.6 million relates to a build-up of materials for the summer construction season. Inventories at our PVC pipe companies are up $1.1 million from December 31, 2005 to meet increased demand in the summer construction season. The $14.8 million increase in receivables includes $11.4 million at our plastic pipe company located in Fargo, North Dakota related to the seasonal increase in sales in this region of the country.

Net cash used in investing activities of continuing operations was $34.1 million for the six months ended June 30, 2006 compared to $36.6 million for the six months ended June 30, 2005. Cash used for capital expenditures increased by $6.8 million between the periods. Cash used for capital expenditures at the electric utility increased by $2.5 million mainly related to replacement of assets damaged in the November 2005 ice storm. Cash used for capital expenditures in the plastics segment increased by $0.5 million between the periods mainly related to the installation of additional equipment at the production plant in Phoenix, Arizona. Cash used for capital expenditures in the manufacturing segment increased by $2.7 million between the periods mainly at DMI in connection with the start up of its Ft. Erie plant. Cash used for capital expenditures in the health services segment increased by $0.9 million between the periods including $0.6 million related to office remodeling and $0.3 million for the purchase of imaging equipment. Net proceeds from the sale of noncurrent assets decreased $2.5 million between the periods reflecting $1.1 million from the sale of several trucks by Wylie in 2005, $0.8 million from the sale of a building for by T.O. Plastics in 2005 and $0.8 million from the sale of equipment at BTD in 2005. We invested $10.7 million in cash, net of cash acquired, in the acquisitions of Performance Tool & Die, Shoreline and Southeast Floating Docks in the first six months of 2005. We made no acquisition expenditures in the first six months of 2006.

Net cash provided by financing activities from continuing operations increased $9.9 million in the six months ended June 30, 2006 compared with the six months ended June 30, 2005 mainly due to a $12.5 million increase in short-term borrowings and checks issued in excess of cash between the periods. A decrease in proceeds from the issuance of common stock of $3.8 million between the quarters reflects the issuance of common stock related to the partial exercise of the underwriters over-allotment option in January 2005. Payments for the retirement of long-term debt decreased by $2.3 million between the periods. The $0.3 million increase in cash paid for debt issuance expenses between the periods relates to the renegotiation and three-year extension of our line-of-credit agreement in April 2006. The $0.6 million increase in dividends paid between the periods is due to an increase of 1.5 cents in the dividend paid per common share in the first six months of 2006 compared with the first six months of 2005 combined with the issuance of additional common shares between the periods.

There were no material changes as of June 30, 2006 in our contractual obligations from those reported under the caption Capital Requirements on page 24 of our 2005 Annual Report to Shareholders. We do not have any material off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships.

Table of Contents

Critical Accounting Policies Involving Significant Estimates

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

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, valuation of forward energy contracts, unbilled electric revenues, unscheduled power exchanges, MISO electric market residual load adjustments, service contract maintenance costs, percentage-of-completion, valuation of stock-based payments and actuarially determined benefits costs. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors.

Goodwill Impairment

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

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

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

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

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (the Act), we have filed cautionary statements identifying important factors that could cause our actual results to differ materially from those discussed in forward-looking statements made by or on behalf of the Company. When used in this Form 10-Q and in future filings by the Company with the Securities and Exchange Commission, in our press releases and in oral statements, words such as may , will , expect , anticipate , continue , estimate , project , believes or 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 government regulations and actions that may have a negative impact on our business and results of operations.

Table of Contents

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

Weather conditions can adversely affect our operations and revenues.

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

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

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

The FERC issued an order on April 25, 2006 that could require MISO to make refunds related to real-time revenue sufficiency guarantee charges that were not allocated to day-ahead virtual supply offers in accordance with MISO s Transmission and Energy Markets Tariff going back to the commencement of the MISO Day 2 market 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 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. We are not yet able to assess what financial impact, if any, this order will have on our operations.

Our electric utility has capitalized $3.3 million in costs related to the planned construction of a second electric generating unit at its Big Stone Plant site as of June 30, 2006. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods would be subject to expense and may not be recoverable.

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

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

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

Competition is a factor in all of our businesses.

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

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

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

Table of Contents

Our plastics segment is highly dependent on a limited number of vendors for PVC resin. In the first six months of 2006, 98% of resin purchased was from two vendors, 51% from one and 47% from the other. The loss of a key vendor or an interruption or delay in the supply of PVC resin could result in reduced sales or increased costs for this business. Reductions in PVC resin prices could negatively impact PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.

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

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

At June 30, 2006 we had limited exposure to market risk associated with interest rates and commodity prices and limited exposure to market risk associated with changes in foreign currency exchange rates. Outstanding trade accounts receivable of the Canadian operations of IPH are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 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. In April 2006, we negotiated a fixed rate of 6.76% on our Lombard US Equipment Finance note (the Lombard note) over the remaining term of the note that has a final payment due on October 2, 2010. As of June 30, 2006 we had $10.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on June 30, 2006, annualized interest expense and pretax earnings would change by approximately $104,000.

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

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

Our energy services subsidiary exited the natural gas marketing business and sold its over-the-counter natural gas forward swap transactions that qualified as derivatives subject to mark-to-market accounting with the sale of its

Table of Contents

natural gas marketing operations in June 2006. Therefore we are no longer exposed to price, market or credit risk from these operations.

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of June 30, 2006 the electric utility had recognized, on a pretax basis, $997,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value the electric utility s forward contracts for the purchases and sales of electricity are determined by survey of counterparties by the electric utility s power services personnel responsible for contract pricing and are benchmarked to regional hub prices as published in *Megawatt Daily* and as observed in the Intercontinental Exchange trading system. Of the forward energy contracts that are marked-to-market as of June 30, 2006, 95% of the forward purchases of electricity had offsetting sales in terms of volumes and delivery periods. The amount of net unrealized marked-to-market gains recognized on forward purchases of electricity not offset by forward sales of electricity as of June 30, 2006 was $71,000.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. With the advent of the MISO Day 2 market in April 2005, several changes were made to the energy risk management policy to recognize new trading opportunities created by this new market. Most of the changes were in new volumetric limits and loss limits to adequately manage the risks associated with these new opportunities. In addition, a Value at Risk (VaR) limit was also implemented to further manage market price risk. Exposure to price risk on any open positions as of June 30, 2006 was not material.

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

(in thousands)	June 30, 2006
Current asset marked-to-market gain	$ 5,883
Regulatory asset deferred marked-to-market loss	1,486
Total assets	7,369
Current liability marked-to-market loss	(4,372)
Regulatory liability deferred marked-to-market gain	(2,000)
Total liabilities	(6,372)
Net fair value of marked-to-market energy contracts	$ 997

(in thousands)	Year-to-date June 30, 2006
Fair value at beginning of year	$ 2,916
Amount realized on contracts entered into in 2005 and settled in 2006	(2,253)
Changes in fair value of contracts entered into in 2005	(555)

Net fair value of contracts entered into in 2005 at end of period		108
Changes in fair value of contracts entered into in 2006		889
Net fair value end of period	$	997

Table of Contents

The $997,000 recognized but unrealized net gain on the forward energy purchases and sales marked to market on June 30, 2006 is expected to be realized on physical settlement as scheduled over the following quarters in the amount listed:

(in thousands)	3rd Quarter 2006	4th Quarter 2006	Total
Net gain	$802	$195	$997

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 June 30, 2006 was $2.0 million. As of June 30, 2006 we had a net credit risk exposure of $9.8 million from 17 counterparties with investment grade credit ratings. We have no exposure at June 30, 2006 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor s), Baa3 (Moody s) or BBB- (Fitch).

The $9.8 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 June 30, 2006. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Item 4. Controls and Procedures

Under the supervision and with the participation of the Company s management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of June 30, 2006, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of June 30, 2006.

During the fiscal quarter ended June 30, 2006, there were no changes in the Company s internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under the caption Risk Factors and Cautionary Statements on pages 26 through 28 of the Company s 2005 Annual Report to Shareholders, which is incorporated by reference to Part I, Item 1A, Risk Factors in the Company s Annual Report on Form 10-K for the year ended December 31, 2005.

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

The Company does not have a publicly announced stock repurchase program. The following table shows previously issued common shares that were surrendered to the Company by employees to pay taxes in connection with the vesting of restricted stock granted to such employees under the Company s 1999 Stock Incentive Plan during the quarter ended June 30, 2006:

Calendar Month	Total number of shares purchased	Average price paid per share
April 2006	16,302	$ 28.28
May 2006		
June 2006		
Total	16,302	

Table of Contents

Item 4. Submission of Matters to a Vote of Security Holders

The Annual Meeting of Shareholders of the Company was held on April 10, 2006, to consider and act upon the following matters: (1) to elect three nominees to the Board of Directors with terms expiring in 2009, (2) to amend the 1999 Employee Stock Purchase Plan to increase the number of available common shares from 400,000 to 900,000, (3) to amend the 1999 Stock Incentive Plan to increase the number of available common shares from 2,600,000 to 3,600,000, to extend the term of the Plan from December 13, 2008 to December 13, 2013, and to make certain other changes to the terms of the Plan, and (4) to ratify the appointment of Deloitte & Touche LLP as the Company s independent registered public accounting firm for the fiscal year ending December 31, 2006. All nominees for directors as listed in the proxy statement were elected. The names of each other director whose term of office continued after the meeting are as follows: Dennis R. Emmen, Arvid R. Liebe, John C. MacFarlane, Kenneth L. Nelson, Nathan I. Partain and Gary J. Spies. The voting results are as follows:

Election of Directors	Shares Voted For	Shares Voted Withheld Authority	Broker Non-Votes
Karen M. Bohn	23,718,943	492,645	-0-
Edward J. McIntyre	23,730,820	480,768	-0-
Joyce Nelson Schuette	23,779,920	431,668	-0-

	Shares Voted For	Shares Voted Against	Shares Voted Abstain	Broker Non-Votes
1999 Employee Stock Purchase Plan Amendment	17,022,566	718,582	836,390	-0-
1999 Stock Incentive Plan Amendment	12,936,097	4,789,615	851,826	-0-
Ratification of Deloitte & Touche LLP as Independent Registered Public Accounting Firm	23,597,802	384,857	228,928	-0-

Item 5. Other Information

On June 1, 2006, Otter Tail Corporation dba Otter Tail Power Company, Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency (collectively, Owners) entered into an Amendment No. 1 to Participation Agreement (Amendment No. 1), amending the Participation Agreement, dated June 30, 2005 (the Participation Agreement), among the Owners. The Participation Agreement, which relates to the planned construction of a new 600 megawatt coal fueled, base-load electric generation plant (the Big Stone II Plant) adjacent to the existing 450 megawatt electric generation plant near Big Stone, South Dakota, is an agreement to jointly develop, finance, construct, own (as tenants in common) and manage the Big Stone II Plant and includes provisions which obligate the parties to the agreement to obtain financing and pay their share of development, construction, operating and maintenance costs for the Big Stone II Plant. The Participation Agreement establishes a Coordinating Committee (the Coordinating Committee) and an Engineering and Operating Committee (the E&O Committee) to manage the development, design, construction, operation and maintenance of the Big Stone II Plant. Amendment No. 1 (i) extends the date by which the E&O Committee must make certain determinations from June 20, 2006 to July 27, 2006, (ii) extends the date on which the Owners, through the Coordinating Committee, must meet to vote on whether to continue the project from June 30, 2006 to a date agreed upon by all of the Owners that shall be on or before August 31, 2006, and (iii) extends the deadline for payment of the amount required under the Participation Agreement to be paid by an Owner withdrawing after continuation of the project is approved from July 31, 2006 to September 30, 2006.

Item 6. Exhibits

4.1 Credit Agreement, dated as of April 26, 2006, among the Company, the Banks named therein, U.S. Bank National Association, as Agent and Lead Arranger; JPMorgan Chase Bank, N.A., as Syndication Agent; and Wells Fargo Bank, National Association, as Documentation Agent (incorporated by reference to Exhibit 4.1 to the Company s Form 8-K filed May 2, 2006)

10.1 Form of Restricted Stock Award Agreement for Directors (incorporated by reference to Exhibit 10.1 to the Company s Form 8-K filed April 13, 2006) *

10.2 Form of 2006 Performance Award Agreement (Effective April 1, 2006) (incorporated by reference to Exhibit 10.2 to the Company s Form 8-K filed April 13, 2006) *

10.3 1999 Employee Stock Purchase Plan, as Amended (incorporated by reference to Exhibit 10.3 to the Company s Form 8-K filed April 13, 2006) *

10.4 1999 Stock Incentive Plan, as Amended (incorporated by reference to Exhibit 10.4 to the Company s Form 8-K filed April 13, 2006) *

10.5 Form of 2006 Restricted Stock Unit Award Agreement *

10.6 Amendment No. 1 to Participation Agreement, dated June 1, 2006, by and among Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., 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 June 30, 2005, by and among the Owners

31.1 Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

31.2 Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32.1 Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

32.2 Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Management contract or compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K.

Table of Contents

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: August 9, 2006

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
4.1	Credit Agreement, dated as of April 26, 2006, among the Company, the Banks named therein, U.S. Bank National Association, as Agent and Lead Arranger; JPMorgan Chase Bank, N.A., as Syndication Agent; and Wells Fargo Bank, National Association, as Documentation Agent (incorporated by reference to Exhibit 4.1 to the Company s Form 8-K filed May 2, 2006)
10.1	Form of Restricted Stock Award Agreement for Directors (incorporated by reference to Exhibit 10.1 to the Company s Form 8-K filed April 13, 2006) *
10.2	Form of 2006 Performance Award Agreement (Effective April 1, 2006) (incorporated by reference to Exhibit 10.2 to the Company s Form 8-K filed April 13, 2006) *
10.3	1999 Employee Stock Purchase Plan, as Amended (incorporated by reference to Exhibit 10.3 to the Company s Form 8-K filed April 13, 2006) *
10.4	1999 Stock Incentive Plan, as Amended (incorporated by reference to Exhibit 10.4 to the Company s Form 8-K filed April 13, 2006) *
10.5	Form of 2006 Restricted Stock Unit Award Agreement *
10.6	Amendment No. 1 to Participation Agreement, dated June 1, 2006, by and among Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., 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 June 30, 2005, by and among the Owners
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Management contract or compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K