MDU RESOURCES GROUP INC
Form 10-Q
November 08, 2007

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For The Quarterly Period Ended September 30, 2007

OR

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 1-3480

MDU Resources Group, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**41-0423660**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 530-1000
(Registrant's telephone number, including area code)

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of November 2, 2007: 182,387,920 shares.

DEFINITIONS

The following abbreviations and acronyms used in this Form 10-Q are defined below:

Abbreviation or Acronym	
2006 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2006
ALJ	Administrative Law Judge
Anadarko	Anadarko Petroleum Corporation
APB	Accounting Principles Board
APB Opinion No. 28	Interim Financial Reporting
Badger Hills Project	Tongue River-Badger Hills Project
Bbl	Barrel of oil or other liquid hydrocarbons
Bcf	Billion cubic feet
BER	Montana Board of Environmental Review
Big Stone Station	450-MW coal-fired electric generating facility located near Big Stone City, South Dakota (22.7 percent ownership)
Big Stone II	Proposed 600-MW coal-fired electric generating facility located near Big Stone City, South Dakota (19.33 percent ownership)
BLM	Bureau of Land Management
Brazilian Transmission Lines	Company’s equity method investment in companies owning ECTE, ENTE and ERTE
Btu	British thermal unit
Carib Power	Carib Power Management LLC
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CBNG	Coalbed natural gas
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial International	Centennial Energy Resources International, Inc., a direct wholly owned subsidiary of Centennial Resources
Centennial Power	Centennial Power, Inc., a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
CMS	Cost Management Services, Inc.
Colorado Federal District Court	U.S. District Court for the District of Colorado
Company	MDU Resources Group, Inc.
D.C. Appeals Court	U.S. Court of Appeals for the District of Columbia Circuit
dk	Decatherm
DRC	Dakota Resource Council
EBSR	Elk Basin Storage Reservoir, one of Williston Basin's natural gas storage reservoirs, which is located in Montana and

	Wyoming
ECTE	Empresa Catarinense de Transmissão de Energia S.A.
EIS	Environmental Impact Statement
ENTE	Empresa Norte de Transmissão de Energia S.A.
EPA	U.S. Environmental Protection Agency
ERTE	Empresa Regional de Transmissão de Energia S.A.
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIN	FASB Interpretation No.
FIN 48	Accounting for Uncertainty in Income Taxes
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Hardin Generating Facility	116-MW coal-fired electric generating facility near Hardin, Montana (sold in the third quarter of 2007)
Hartwell	Hartwell Energy Limited Partnership, a former equity method investment of the Company (sold in the third quarter of 2007)
Howell	Howell Petroleum Corporation, a wholly owned subsidiary of Anadarko
Indenture	Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York, as Trustee
Innovatum	Innovatum, Inc., a former indirect wholly owned subsidiary of WBI Holdings (the stock and a portion of Innovatum's assets were sold during the fourth quarter of 2006)
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
kWh	Kilowatt-hour
LWG	Lower Willamette Group
MBbls	Thousand barrels of oil or other liquid hydrocarbons
MBI	Morse Bros., Inc., an indirect wholly owned subsidiary of Knife River
Mcf	Thousand cubic feet
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial International
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million decatherms
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana State Department of Environmental Quality
Montana Federal District Court	U.S. District Court for the District of Montana
Mortgage	Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustees
MPX	

	MPX Termoceara Ltda. (49 percent ownership, sold in June 2005)
MTPSC	Montana Public Service Commission
MW	Megawatt
ND Health Department	North Dakota Department of Health
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
Ninth Circuit	U.S. Ninth Circuit Court of Appeals
NPRC	Northern Plains Resource Council
OPUC	Oregon Public Utility Commission
Order on Rehearing	Order on Rehearing and Compliance and Remanding Certain Issues for Hearing
Oregon DEQ	Oregon State Department of Environmental Quality
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
PSD	Prevention of Significant Deterioration
SEC	U.S. Securities and Exchange Commission
SEIS	Supplemental Environmental Impact Statement
SFAS	Statement of Financial Accounting Standards
SFAS No. 71	Accounting for the Effects of Certain Types of Regulation
SFAS No. 87	Employers' Accounting for Pensions
SFAS No. 109	Accounting for Income Taxes
SFAS No. 142	Goodwill and Other Intangible Assets
SFAS No. 144	Accounting for the Impairment or Disposal of Long-Lived Assets
SFAS No. 157	Fair Value Measurements
SFAS No. 159	The Fair Value Option for Financial Assets and Financial Liabilities
Trinity Generating Facility	225-MW natural gas-fired electric generating facility in Trinidad and Tobago (49.99 percent ownership, sold in the first quarter of 2007)
TRWUA	Tongue River Water Users' Association
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Williston Basin	Williston Basin Interstate Pipeline Company, an indirect wholly owned subsidiary of WBI Holdings
WUTC	Washington Utilities and Transportation Commission
Wyoming Federal District Court	U.S. District Court for the District of Wyoming
Wyoming DEQ	Wyoming State Department of Environmental Quality

INTRODUCTION

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Its principal executive offices are at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

Montana-Dakota, through the electric and natural gas distribution segments, generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. Cascade distributes natural gas in Washington and Oregon. These operations also supply related value-added products and services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (comprised of the pipeline and energy services and the natural gas and oil production segments), Knife River (construction materials and mining segment), MDU Construction Services (construction services segment), Centennial Resources (independent power production segment) and Centennial Capital (reflected in the Other category). For more information on the Company's business segments, see Note 17.

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PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

MDU RESOURCES GROUP, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$ 235,562	$ 171,954	$ 699,063	$ 633,590
Construction services, natural gas and oil production, construction materials and mining, and other	1,009,748	1,001,724	2,316,103	2,305,040
	1,245,310	1,173,678	3,015,166	2,938,630
Operating expenses:				
Fuel and purchased power	20,331	19,133	52,938	51,208
Purchased natural gas sold	60,887	28,648	200,016	194,969
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	59,650	40,012	150,967	120,112
Construction services, natural gas and oil production, construction materials and mining, independent power production and other	807,139	805,985	1,882,769	1,889,106
Depreciation, depletion and amortization	78,400	67,033	218,246	192,855
Taxes, other than income	39,747	31,438	109,320	95,654
	1,066,154	992,249	2,614,256	2,543,904
Operating income	179,156	181,429	400,910	394,726
Earnings from equity method investments	11,782	2,829	17,867	8,931
Other income	3,456	4,469	5,670	9,733
Interest expense	19,074	20,240	53,928	53,402
Income before income taxes	175,320	168,487	370,519	359,988
Income taxes	70,823	61,377	142,580	131,981
Income from continuing operations	104,497	107,110	227,939	228,007
Income from discontinued operations, net of tax (Note 4)	96,765	1,377	109,459	5,169
Net income	201,262	108,487	337,398	233,176
Dividends on preferred stocks	172	171	513	514

Earnings on common stock	$ 201,090	$ 108,316	$ 336,885	$ 232,662
Earnings per common share -- basic				
Earnings before discontinued operations	$ .57	$ .59	$ 1.25	$ 1.26
Discontinued operations, net of tax	.53	.01	.60	.03
Earnings per common share -- basic	$ 1.10	$ .60	$ 1.85	$ 1.29
Earnings per common share -- diluted				
Earnings before discontinued operations	$ .57	$ .59	$ 1.24	$ 1.26
Discontinued operations, net of tax	.53	.01	.60	.03
Earnings per common share -- diluted	$ 1.10	$ .60	$ 1.84	$ 1.29
Dividends per common share	$ .1450	$ .1350	$ .4150	$ .3884
Weighted average common shares outstanding -- basic	182,192	180,291	181,796	180,010
Weighted average common shares outstanding -- diluted	183,171	181,307	182,780	181,010

The accompanying notes are an integral part of these consolidated financial statements.

MDU RESOURCES GROUP, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2007	September 30, 2006	December 31, 2006
	(In thousands, except shares and per share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 94,528	$ 68,786	$ 73,078
Receivables, net	748,858	714,754	622,478
Inventories	254,710	225,234	204,440
Deferred income taxes	---	8,698	---
Prepayments and other current assets	129,421	77,615	81,083
Current assets held for sale and related to discontinued operations	594	12,529	12,656
	1,228,111	1,107,616	993,735
Investments	112,283	155,989	155,111
Property, plant and equipment	5,740,966	4,620,912	4,727,725
Less accumulated depreciation, depletion and amortization	2,203,218	1,683,286	1,735,302
	3,537,748	2,937,626	2,992,423
Deferred charges and other assets:			
Goodwill	430,644	226,672	224,298
Other intangible assets, net	29,115	22,418	22,802
Other	152,607	100,542	103,840
Noncurrent assets held for sale and related to discontinued operations	140	415,693	411,265
	612,506	765,325	762,205
	$ 5,490,648	$ 4,966,556	$ 4,903,474
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Long-term debt due within one year	$ 131,971	$ 98,980	$ 84,034
Accounts payable	310,509	318,272	289,836
Taxes payable	114,427	44,683	54,290
Deferred income taxes	3,069	---	5,969
Dividends payable	26,616	24,569	24,606
Other accrued liabilities	266,149	163,565	180,327
Current liabilities held for sale and related to discontinued operations	---	6,110	14,900
	852,741	656,179	653,962
Long-term debt	1,146,708	1,307,050	1,170,548
Deferred credits and other liabilities:			
Deferred income taxes	629,582	558,044	546,602
Other liabilities	398,353	293,024	336,916
Noncurrent liabilities held for sale and related to discontinued operations	---	31,429	30,533
	1,027,935	882,497	914,051
Commitments and contingencies			
Stockholders' equity:			
Preferred stocks	15,000	15,000	15,000
Common stockholders' equity:			
Common stock			
Shares issued -- $1.00 par value 182,914,769 at September 30, 2007, 181,279,379 at September 30, 2006 and 181,557,543 at December 31,	182,915	181,279	181,558

2006			
Other paid-in capital	909,805	872,973	874,253
Retained earnings	1,365,497	1,046,933	1,104,210
Accumulated other comprehensive income (loss)	(6,327)	8,271	(6,482)
Treasury stock at cost – 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,448,264	2,105,830	2,149,913
Total stockholders' equity	2,463,264	2,120,830	2,164,913
	$ 5,490,648	$ 4,966,556	$ 4,903,474

The accompanying notes are an integral part of these consolidated financial statements.

MDU RESOURCES GROUP, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In thousands)	
Operating activities:		
Net income	$ 337,398	$ 233,176
Income from discontinued operations, net of tax	109,459	5,169
Income from continuing operations	227,939	228,007
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	218,246	192,855
Earnings, net of distributions, from equity method investments	(12,448)	(3,164)
Deferred income taxes	41,387	26,567
Changes in current assets and liabilities, net of acquisitions:		
Receivables	(67,602)	(100,494)
Inventories	(35,181)	(51,059)
Other current assets	(39,563)	(12,299)
Accounts payable	(19,962)	66,089
Other current liabilities	40,182	10,153
Other noncurrent changes	7,230	14,302
Net cash provided by continuing operations	360,228	370,957
Net cash provided by (used in) discontinued operations	(46,750)	18,203
Net cash provided by operating activities	313,478	389,160
Investing activities:		
Capital expenditures	(380,087)	(370,535)
Acquisitions, net of cash acquired	(341,790)	(111,710)
Net proceeds from sale or disposition of property	16,264	19,335
Investments	3,275	(55,956)
Proceeds from sale of equity method investments	56,150	---
Net cash used in continuing operations	(646,188)	(518,866)
Net cash provided by (used in) discontinued operations	548,216	(40,091)
Net cash used in investing activities	(97,972)	(558,957)
Financing activities:		
Issuance of short-term borrowings	310,000	---
Repayment of short-term borrowings	(310,000)	---
Issuance of long-term debt	85,000	394,504
Repayment of long-term debt	(226,791)	(206,437)
Proceeds from issuance of common stock	16,580	13,255
Dividends paid	(74,025)	(68,881)
Tax benefit on stock-based compensation	4,883	2,050
Net cash provided by (used in) continuing operations	(194,353)	134,491
Net cash provided by discontinued operations	---	248
Net cash provided by (used in) financing activities	(194,353)	134,739
Effect of exchange rate changes on cash and cash equivalents	297	(1,654)
Increase (decrease) in cash and cash equivalents	21,450	(36,712)
Cash and cash equivalents – beginning of year	73,078	105,498
Cash and cash equivalents – end of period	$ 94,528	$ 68,786

The accompanying notes are an integral part of these consolidated financial statements.

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

September 30, 2007 and 2006
(Unaudited)

1. **Basis of presentation**

The accompanying consolidated interim financial statements were prepared in conformity with the basis of presentation reflected in the consolidated financial statements included in the Company's 2006 Annual Report, and the standards of accounting measurement set forth in APB Opinion No. 28 and any amendments thereto adopted by the FASB. Interim financial statements do not include all disclosures provided in annual financial statements and, accordingly, these financial statements should be read in conjunction with those appearing in the 2006 Annual Report. The information is unaudited but includes all adjustments that are, in the opinion of management, necessary for a fair presentation of the accompanying consolidated interim financial statements.

2. **Seasonality of operations**

Some of the Company's operations are highly seasonal and revenues from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Accordingly, the interim results for particular businesses, and for the Company as a whole, may not be indicative of results for the full fiscal year.

3. **Acquisitions**

During the first nine months of 2007, the Company acquired construction materials and mining businesses in North Dakota, Texas and Wyoming, a construction services business in Nevada, and Cascade, a natural gas distribution business, as discussed below. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2007, consisting of the Company's common stock and cash and the outstanding indebtedness of Cascade, was $519.6 million.

On July 2, 2007, the acquisition of Cascade was finalized and Cascade became an indirect wholly owned subsidiary of the Company. The acquisition of Cascade was funded with cash (largely proceeds from the sale of the domestic independent power production assets) and debt. Cascade’s natural gas service areas are in Washington and Oregon. Cascade is a part of the Company’s natural gas distribution segment.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. Final fair market values, for certain of the above acquisitions, are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date. The results of operations of the acquired businesses and properties are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

4. **Discontinued operations**

Innovatum, a component of the pipeline and energy services segment, specialized in cable and pipeline magnetization and location. During the third quarter of 2006, the Company initiated a plan to sell Innovatum because the Company determined that Innovatum is a non-strategic asset. During the fourth quarter of 2006, the stock and a portion of the assets of Innovatum were sold and the Company expects to sell the remaining assets of Innovatum in the fourth quarter of 2007. The loss on disposal on the portion of Innovatum that has been sold was not material. The Company does not expect to have any involvement in the operations of Innovatum after the sale.

During the fourth quarter of 2006, the Company initiated a plan to sell certain of the domestic assets of Centennial Resources, which largely comprise the independent power production segment. The plan to sell was based on the increased market demand for independent power production assets, combined with the Company's desire to efficiently fund future capital needs. The results of operations of these assets were shown in continuing operations in the Company's financial statements in the 2006 Annual Report as the Company intended to have significant continuing involvement with these assets in the form of continuing existing operation and maintenance agreements between CEM and these assets after the sale.

The Company subsequently committed to a plan to sell CEM due to strong interest in the operations of CEM during the bidding process for the domestic independent power production assets in the first quarter of 2007. As a result of the Company's commitment to a plan to sell CEM, the Company would no longer have significant continuing involvement in the operations of the other domestic independent power production assets after the sale. Therefore, in accordance with SFAS No. 144, the results of operations of the domestic independent power production assets, including CEM, are presented as discontinued operations.

On July 10, 2007, Centennial Resources sold its domestic independent power production business consisting of Centennial Power and CEM to Bicent Power LLC (formerly known as Montana Acquisition Company LLC). The transaction was valued at $636 million, which included the assumption of approximately $36 million of project-related debt. The gain on the sale of the assets, excluding the gain on the sale of Hartwell as discussed in Note 13, was approximately $85.4 million (after tax). A portion of the proceeds from the sale was used to pay a dividend to the Company. This dividend was then used to prepay, in part, the outstanding term loan indebtedness that was incurred by the Company to fund the Cascade acquisition. The remaining proceeds of the sale are anticipated to provide additional cash for growth opportunities that exist in the Company's core lines of business.

In accordance with SFAS No. 144, the Company's consolidated financial statements and accompanying notes for prior periods have been restated to present the results of operations of Innovatum and the domestic independent power production assets as discontinued operations. In addition, the assets and liabilities of these operations are treated as held for sale, and as a result, no depreciation, depletion and amortization expense was recorded from the time each of the assets was classified as held for sale, respectively.

In accordance with SFAS No. 142, at the time the Company committed to the plan to sell each of the assets, the Company was required to test the respective assets for goodwill impairment. The fair value of Innovatum, a reporting unit for goodwill impairment testing, was estimated using the expected proceeds from the sale, which was estimated to be the current book value of the assets of Innovatum other than its goodwill. As a result, a goodwill impairment of $4.3 million (before tax) was recognized and recorded as part of discontinued operations, net of tax, in the Consolidated Statements of Income in the third quarter of 2006. There were no goodwill impairments associated with the other assets held for sale.

Operating results related to Innovatum were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In thousands)			
Operating revenues	$ 593	$ 654	$ 1,283	$ 1,796
Income (loss) from discontinued operations before income tax expense (benefit)	218	(4,743)	246	(5,606)
Income tax expense (benefit)	29	(3,132)	---	(3,398)
Income (loss) from discontinued operations, net of tax	$ 189	$ (1,611)	$ 246	$ (2,208)

The income tax benefit for the three and nine months ended September 30, 2006, is larger than the customary relationship between the income tax benefit and the loss before tax due to a capital loss tax benefit (which reflects the effect of the $4.0 million and $4.3 million goodwill impairments in 2004 and 2006, respectively) resulting from the sale of the Innovatum stock.

Operating results related to the domestic independent power production assets were as follows:

	Three Months Ended September 30, 2007	2006	Nine Months Ended September 30, 2007	2006
		(In thousands)		
Operating revenues	$ 26,980	$ 16,958	$ 125,867	$ 39,941
Income from discontinued operations (including gain on disposal of $142.4 million) before income tax expense (benefit)	160,612	3,166	177,535	6,197
Income tax expense (benefit)	64,036	178	68,322	(1,180)
Income from discontinued operations, net of tax	$ 96,576	$ 2,988	$ 109,213	$ 7,377

The carrying amounts of the major assets and liabilities related to the domestic independent power production assets held for sale, as well as the major assets and liabilities related to Innovatum, were as follows:

	September 30, 2007	September 30, 2006	December 31, 2006
		(In thousands)	
Cash and cash equivalents	$ ---	$ 1,419	$ 1,878
Receivables, net	---	7,016	8,307
Inventories	594	1,164	490
Prepayments and other current assets	---	2,930	1,981
Total current assets held for sale and related to discontinued operations	$ 594	$ 12,529	$ 12,656
Net property, plant and equipment	$ 140	$ 393,234	$ 390,679
Goodwill	---	11,167	11,167
Other intangible assets, net	---	7,432	7,162
Other	---	3,860	2,257
Total noncurrent assets held for sale and related to discontinued operations	$ 140	$ 415,693	$ 411,265
Accounts payable	$ ---	$ 1,143	$ 11,557
Other accrued liabilities	---	4,967	3,343
Total current liabilities held for sale and related to discontinued operations	$ ---	$ 6,110	$ 14,900
Deferred income taxes	$ ---	$ 28,957	$ 27,956
Other liabilities	---	2,472	2,577
Total noncurrent liabilities held for sale and related to discontinued operations	$ ---	$ 31,429	$ 30,533

5. **Common stock**

At the Annual Meeting of Stockholders held on April 24, 2007, the Company's common stockholders approved an amendment to the Restated Certificate of Incorporation that increased the authorized number of common shares from 250 million shares to 500 million shares with a par value of $1.00 per share.

6. **Allowance for doubtful accounts**

The Company's allowance for doubtful accounts as of September 30, 2007 and 2006, and December 31, 2006, was $12.2 million, $5.9 million and $7.7 million, respectively.

7. **Natural gas in underground storage**

Natural gas in underground storage for the Company's regulated operations is generally carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year was included in inventories and was $49.1 million, $43.8 million and $32.6 million at September 30, 2007 and 2006, and December 31, 2006, respectively. The remainder of natural gas in underground storage was included in other assets and was $44.2 million, $43.2 million, and $44.2 million at September 30, 2007 and 2006, and December 31, 2006, respectively.

8. **Inventories**

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $102.4 million, $92.1 million and $88.1 million; materials and supplies of $68.2 million, $61.4 million and $54.1 million; and other inventories of $35.0 million, $27.9 million and $29.6 million, as of September 30, 2007 and 2006, and December 31, 2006, respectively. These inventories were stated at the lower of average cost or market value.

9. **Earnings per common share**

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the applicable period. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the applicable period, plus the effect of outstanding stock options, restricted stock grants and performance share awards. For the three and nine months ended September 30, 2007 and 2006, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

10. **Cash flow information**

Cash expenditures for interest and income taxes were as follows:

	Nine Months Ended September 30,	
	2007	2006
	(In thousands)	
Interest, net of amount capitalized	$ 55,139	$ 48,957
Income taxes	$ 153,030	$ 105,264

Income taxes paid for the nine months ended September 30, 2007, increased from the amount paid for the nine months ended September 30, 2006, primarily due to higher estimated quarterly income tax payments due in large part to the gain on the sale of the domestic independent power production assets as discussed in Note 4.

11. **New accounting standards**

FIN 48 In July 2006, the FASB issued FIN 48. FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements. The criterion allows for recognition in the financial statements of a tax position when it is more likely than not that the position will be sustained upon examination. FIN 48 was effective for the Company on January 1, 2007. The adoption of FIN 48 did not have a material effect on the Company’s financial position or results of operations. For more information on the implementation of FIN 48, see Note 16.

SFAS No. 157 In September 2006, the FASB issued SFAS No. 157. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The standard applies under other accounting pronouncements that require or permit fair value measurements with certain exceptions. SFAS No. 157 is effective for the Company on January 1, 2008. The Company is evaluating the effects of the adoption of SFAS No. 157.

SFAS No. 159 In February 2007, the FASB issued SFAS No. 159. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for the Company on January 1, 2008. The Company is evaluating the effects of the adoption of SFAS No. 159.

12. **Comprehensive income**

Comprehensive income is the sum of net income as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges and foreign currency translation adjustments. For more information on derivative instruments, see Note 15.

Comprehensive income, and the components of other comprehensive income (loss) and related tax effects, were as follows:

	Three Months Ended September 30,	
	2007	2006
	(In thousands)	
Net income	$ 201,262	$ 108,487
Other comprehensive income:		
Net unrealized gain (loss) on derivative instruments qualifying as hedges:		
Net unrealized gain on derivative instruments arising during the period, net of tax of $3,075 and $8,709 in 2007 and 2006, respectively	4,958	13,912
Less: Reclassification adjustment for gain on derivative instruments included in net income, net of tax of $3,247 and $2,654 in 2007 and 2006, respectively	5,187	4,240
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(229)	9,672
Foreign currency translation adjustment	2,795	(401)
	2,566	9,271
Comprehensive income	$ 203,828	$ 117,758

	Nine Months Ended September 30,	
	2007	2006
	(In thousands)	
Net income	$ 337,398	$ 233,176
Other comprehensive income:		
Net unrealized gain (loss) on derivative instruments qualifying as hedges:		

Net unrealized gain on derivative instruments arising during the period, net of tax of $4,066 and $15,840 in 2007 and 2006, respectively	6,541	25,304
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $9,305 and $(12,121) in 2007 and 2006, respectively	14,864	(19,361)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(8,323)	44,665
Foreign currency translation adjustment	8,478	(2,578)
	155	42,087
Comprehensive income	$ 337,553	$ 275,263

13. **Equity method investments**

The Company's equity method investments at September 30, 2007, include the Brazilian Transmission Lines.

In August 2006, MDU Brasil acquired ownership interests in companies owning the Brazilian Transmission Lines. The interests involve the ENTE (13.3-percent ownership interest), ERTE (13.3-percent ownership interest) and ECTE (25-percent ownership interest) electric transmission lines, which are primarily in northeastern and southern Brazil.

In February 2004, Centennial International acquired 49.99 percent of Carib Power. Carib Power, through a wholly owned subsidiary, owns a 225-MW natural gas-fired electric generating facility in Trinidad and Tobago. On February 26, 2007, the Company sold its interest in Carib Power. The sale did not have a significant effect on the Company's results of operations.

In September 2004, Centennial Resources, through indirect wholly owned subsidiaries, acquired a 50-percent ownership interest in Hartwell, which owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. On July 10, 2007, the Company sold its ownership interest in Hartwell, and realized a gain of $10.1 million ($6.1 million after tax) from the sale which is recorded in earnings from equity method investments on the Consolidated Statements of Income.

At September 30, 2007 and 2006, and December 31, 2006, the Company's equity method investments had total assets of $380.5 million, $576.6 million and $583.6 million, respectively, and long-term debt of $210.3 million, $324.3 million and $321.5 million, respectively. The Company's investment in its equity method investments was approximately $55.2 million, $99.2 million and $102.0 million, including undistributed earnings of $5.2 million, $6.6 million and $8.5 million, at September 30, 2007 and 2006, and December 31, 2006, respectively.

14. **Goodwill and other intangible assets**

The changes in the carrying amount of goodwill were as follows:

Nine Months Ended September 30, 2007	Balance as of January 1, 2007	Goodwill Acquired During the Year* (In thousands)	Balance as of September 30, 2007
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	177,167	177,167
Construction services	86,942	4,443	91,385
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and mining	136,197	24,736	160,933
Independent power production	---	---	---

Other	---	---	---
Total	$ 224,298	$ 206,346	$ 430,644

*Includes purchase price adjustments that were not material related to acquisitions in a prior period.

Nine Months Ended September 30, 2006	Balance as of January 1, 2006	Goodwill Acquired During the Year* (In thousands)	Balance as of September 30, 2006
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	80,970	5,956	86,926
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and mining	133,264	5,323	138,587
Independent power production	---	---	---
Other	---	---	---
Total	$ 215,393	$ 11,279	$ 226,672

*Includes purchase price adjustments that were not material related to acquisitions in a prior period.

Year Ended December 31, 2006	Balance as of January 1, 2006	Goodwill Acquired During the Year* (In thousands)	Balance as of December 31, 2006
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	80,970	5,972	86,942
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and mining	133,264	2,933	136,197
Independent power production	---	---	---
Other	---	---	---
Total	$ 215,393	$ 8,905	$ 224,298

*Includes purchase price adjustments that were not material related to acquisitions in a prior period.

Other intangible assets were as follows:

	September 30, 2007	September 30, 2006 (In thousands)	December 31, 2006
Amortizable intangible assets:			
Customer relationships	$ 21,518	$ 6,900	$ 13,030
Accumulated amortization	(3,609)	(1,127)	(1,890)
	17,909	5,773	11,140
Noncompete agreements	10,596	12,886	12,886
Accumulated amortization	(3,170)	(9,104)	(8,540)
	7,426	3,782	4,346
Acquired contracts	2,539	8,165	8,307

Accumulated amortization	(1,281)	(4,242)	(4,646)
	1,258	3,923	3,661
Other	3,401	9,512	5,062
Accumulated amortization	(879)	(1,096)	(1,407)
	2,522	8,416	3,655
Unamortizable intangible assets	---	524	---
Total	$ 29,115	$ 22,418	$ 22,802

The unamortizable intangible assets at September 30, 2006, were recognized in accordance with SFAS No. 87, which requires that if an additional minimum liability is recognized, an equal amount shall be recognized as an intangible asset provided that the asset recognized shall not exceed the amount of unrecognized prior service cost.

Amortization expense for amortizable intangible assets for the three and nine months ended September 30, 2007, was $1.0 million and $2.9 million, respectively. Amortization expense for the three and nine months ended September 30, 2006, and for the year ended December 31, 2006, was $1.2 million, $3.3 million and $4.3 million, respectively. Estimated amortization expense for amortizable intangible assets is $4.8 million in 2007, $5.5 million in 2008, $4.3 million in 2009, $3.4 million in 2010, $2.8 million in 2011 and $11.2 million thereafter.

15. Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties. The Company's policy requires that natural gas and oil price derivative instruments at Fidelity and interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. Cascade is authorized to maintain a portfolio of natural gas derivative instruments not to exceed a period of three years. The Company's policy requires settlement of natural gas and oil price derivative instruments monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings and credit exposure limitations. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties.

As of September 30, 2007, the Company had no outstanding foreign currency or interest rate hedges. The following information should be read in conjunction with Note 7 in the Company's Notes to Consolidated Financial Statements in the 2006 Annual Report.

Cascade core

At September 30, 2007, Cascade held natural gas swap agreements which were not designated as hedges.

Cascade utilizes natural gas swap agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas on its forecasted purchases of natural gas for core customers in accordance with authority granted by the WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Cascade applies SFAS No. 71 and records periodic changes in the fair market value of the derivative instruments on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract.

Fidelity and Cascade non-core

At September 30, 2007, Fidelity held natural gas and oil swap and collar derivative instruments designated as cash flow hedging instruments. Cascade held natural gas swap derivative instruments designated as cash flow hedging instruments.

Fidelity utilizes natural gas and oil price swap and collar agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on its forecasted sales of natural gas and oil production. Cascade utilizes natural gas swap agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas on its forecasted purchases of natural gas for non-core customers. Cascade’s non-core customers, who are not covered by the purchased gas cost adjustment mechanism, are generally large industrial, electric generation and institutional customers. Each of the price swap and collar agreements was designated as a hedge of the forecasted sale of the related production or as a hedge of the forecasted purchase of the related commodity.

The fair value of the hedging instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). At the date the natural gas or oil quantities are settled, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings. The proceeds received for natural gas and oil production and the amount paid for natural gas purchases are also generally based on market prices.

For the three and nine months ended September 30, 2007, the amount of hedge ineffectiveness was immaterial. In the second quarter of 2006, Fidelity had oil collar agreements that became ineffective and no longer qualified for hedge accounting. The ineffectiveness related to these collar agreements resulted in a gain of approximately $841,000 (before tax) for the three months ended September 30, 2006, and a loss of approximately $138,000 (before tax) for the nine months ended September 30, 2006. The ineffectiveness related to these collar agreements was recorded in operation and maintenance expense. The amount of hedge ineffectiveness on the remaining hedges was immaterial for the three and nine months ended September 30, 2006. For the three and nine months ended September 30, 2007 and 2006, there were no components of the derivative instruments’ gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of September 30, 2007, the maximum term of the swap and collar agreements, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 15 months. The Company estimates that over the next 12 months, net gains of approximately $10.7 million (after tax) will be reclassified from accumulated other comprehensive income into earnings, subject to changes in natural gas market prices, as the hedged transactions affect earnings.

16. **Income taxes**

On January 1, 2007, the Company adopted FIN 48 as discussed in Note 11.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2003.

Upon the adoption of FIN 48, the Company recognized a decrease in the liability for unrecognized tax benefits, which was not material and was accounted for as an increase to the January 1, 2007, balance of retained earnings. At the date of adoption, the amount of unrecognized tax benefits was $4.5 million.

Included in the balance of unrecognized tax benefits at the date of adoption are $3.0 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits at the date of adoption that, if recognized, would affect the effective tax rate was $1.5 million, including $304,000 for the payment of interest and penalties. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Prior to the sale of the domestic independent power production assets on July 10, 2007, as discussed in Note 4, the Company considered earnings (including the gain from the sale of its foreign equity method investment in a natural gas-fired electric generating facility in Brazil in 2005) to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes were recorded with respect to such earnings. Following the sale of these assets, the Company reconsidered its long-term plans for future development and expansion of its foreign investment, and has determined that it has no immediate plans to explore or invest in additional foreign investments at this time. Therefore, in accordance with SFAS No. 109, deferred income taxes must now be accrued with respect to the temporary differences which had not been previously recorded. The cumulative undistributed earnings at September 30, 2007, were approximately $36 million. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings and recognized in the third quarter of 2007 was approximately $10 million. Future earnings will also be subject to additional U.S. taxes, net of allowable foreign tax credits.

17. **Business segment data**

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of investments in companies owning electric transmission lines.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states as well as in Minnesota, Oregon and Washington. These operations also supply related value-added products and services.

The construction services segment specializes in electric line construction, pipeline construction, utility excavation, inside electrical wiring, cabling and mechanical work, fire protection and the manufacture and distribution of specialty equipment.

The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The pipeline and energy services segment also provides energy-related management services.

The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration, development and production activities primarily in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and mining segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated construction services. The construction materials and mining segment operates in the north central, southern and western United States and Alaska and Hawaii.

The independent power production segment's international operation has investments in companies that own electric transmission lines. Prior to the July 10, 2007 sale, this segment's domestic operation owned, built and operated electric generating facilities in the United States and had investments in natural resource-based projects. For more information regarding the discontinued operations of the domestic operations of this segment and the sale of these assets, see Note 4.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property.

The information below follows the same accounting policies as described in Note 1 of the Company's Notes to Consolidated Financial Statements in the 2006 Annual Report. Information on the Company's businesses was as follows:

Three Months Ended September 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 53,986	$ ---	$ 5,668
Natural gas distribution	90,706	---	(4,544)
Pipeline and energy services	90,870	11,627	9,408
	235,562	11,627	10,532
Construction services	293,286	46	13,678
Natural gas and oil production	76,839	46,242	33,182
Construction materials and mining	639,623	---	50,389
Independent power production	---	---	93,139
Other	---	2,446	170
	1,009,748	48,734	190,558
Intersegment eliminations	---	(60,361)	---
Total	$ 1,245,310	$ ---	$ 201,090

Three Months Ended September 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 53,204	$ ---	$ 5,698
Natural gas distribution	31,378	---	(2,347)
Pipeline and energy services	87,372	16,434	7,141
	171,954	16,434	10,492
Construction services	262,188	139	8,300
Natural gas and oil production	71,885	50,607	35,012
Construction materials and mining	667,651	---	52,520
Independent power production	---	---	1,714
Other	---	1,773	278
	1,001,724	52,519	97,824
Intersegment eliminations	---	(68,953)	---

Total	$ 1,173,678	$ ---	$ 108,316

Nine Months Ended September 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 145,681	$ ---	$ 13,020
Natural gas distribution	280,172	---	1,041
Pipeline and energy services	273,210	54,579	21,346
	699,063	54,579	35,407
Construction services	793,406	520	33,938
Natural gas and oil production	200,032	169,023	98,969
Construction materials and mining	1,322,665	---	66,135
Independent power production	---	---	101,627
Other	---	7,326	809
	2,316,103	176,869	301,478
Intersegment eliminations	---	(231,448)	---
Total	$ 3,015,166	$ ---	$ 336,885

Nine Months Ended September 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 139,109	$ ---	$ 10,003
Natural gas distribution	229,497	---	446
Pipeline and energy services	264,984	67,808	17,290
	633,590	67,808	27,739
Construction services	728,936	385	23,377
Natural gas and oil production	189,890	175,104	107,249
Construction materials and mining	1,386,214	---	68,957
Independent power production	---	---	4,560
Other	---	5,861	780
	2,305,040	181,350	204,923
Intersegment eliminations	---	(249,158)	---
Total	$ 2,938,630	$ ---	$ 232,662

The pipeline and energy services segment recognized income from discontinued operations, net of tax, of $189,000 and $246,000 for the three and nine months ended September 30, 2007, respectively and a loss from discontinued operations, net of tax of $1.6 million and $2.2 million for the three and nine months ended September 30, 2006, respectively. The independent power production segment recognized income from discontinued operations, net of tax, of $96.6 million, $109.2 million, $3.0 million and $7.4 million for the three and nine months ended September 30, 2007 and 2006, respectively. Excluding the income (loss) from discontinued operations at pipeline and energy services, earnings (loss) from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from construction services, natural gas and oil production, construction materials and mining, independent power production, and other are all from nonregulated operations.

18. **Employee benefit plans**

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans were as follows:

Three Months Ended September 30,	Pension Benefits 2007	Pension Benefits 2006	Other Postretirement Benefits 2007	Other Postretirement Benefits 2006
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 2,568	$ 3,197	$ 446	$ 782
Interest cost	5,389	5,861	1,071	1,107
Expected return on assets	(6,497)	(7,983)	(1,235)	(1,643)
Amortization of prior service cost	183	233	(662)	14
Recognized net actuarial (gain) loss	582	569	121	(18)
Amortization of net transition obligation (asset)	---	---	496	704
Net periodic benefit cost, including amount capitalized	2,225	1,877	237	946
Less amount capitalized	220	179	104	80
Net periodic benefit cost	$ 2,005	$ 1,698	$ 133	$ 866

Nine Months Ended September 30,	Pension Benefits 2007	Pension Benefits 2006	Other Postretirement Benefits 2007	Other Postretirement Benefits 2006
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 6,829	$ 7,799	$ 1,426	$ 1,725
Interest cost	13,752	14,009	3,189	2,964
Expected return on assets	(16,661)	(17,419)	(3,607)	(3,494)
Amortization of prior service cost	599	746	(637)	37
Recognized net actuarial (gain) loss	1,082	1,587	(28)	(187)
Amortization of net transition obligation (asset)	---	(2)	1,662	1,766
Net periodic benefit cost, including amount capitalized	5,601	6,720	2,005	2,811
Less amount capitalized	588	560	245	205
Net periodic benefit cost	$ 5,013	$ 6,160	$ 1,760	$ 2,606

In addition to the qualified plan defined pension benefits reflected in the table, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees. The Company's net periodic benefit cost for these plans for the three and nine months ended September 30, 2007, was $2.1 million and $6.0 million, respectively. The Company’s net periodic benefit cost for these plans for the three and nine months ended September 30, 2006, was $1.8 million and $5.7 million, respectively.

19. **<u>Regulatory matters and revenues subject to refund</u>**

In August 2006, CMS, a competing gas marketer, filed a complaint against Cascade before the WUTC alleging Cascade had entered into gas supply sales contracts with its non-core, transportation-only customers in violation of state law by not filing tariffs and copies of the gas supply contracts with the WUTC. CMS’s complaint additionally raised claims of undue preference and discrimination. On January 12, 2007, the WUTC entered an order allowing Cascade to continue to make gas supply sales to non-core customers but requiring Cascade to file its tariffs and sales contracts with the WUTC. On February 12, 2007, Cascade filed revisions to its tariffs reflecting gas supply service options available to non-core customers and on March 30, 2007, filed notice with the WUTC that it was reactivating a nonregulated affiliate to make retail gas sales to non-core customers. The WUTC suspended the tariff filings and consolidated the tariff proceeding with Cascade’s filing to re-establish an affiliate to make non-core customer gas supply sales. On May 17, 2007, following a series of motions for clarification of the order, the presiding ALJ closed the CMS complaint docket and directed the WUTC Staff to conduct an investigation of the gas supply sales contracts on an informal basis. CMS filed a petition for interlocutory review which was granted by the WUTC on October 12, 2007. The WUTC order allows CMS to pursue its complaint for undue preference and discrimination and to add a claim for price cross-subsidization. The WUTC is expected to issue a procedural order in the proceeding after a pre-hearing conference.

On July 12, 2007, Montana-Dakota filed an application with the MTPSC for an electric rate increase. Montana-Dakota requested a total of $7.8 million annually or approximately 22 percent above current rates. Montana-Dakota is requesting a fuel and purchased power tracking adjustment and an off-system sales margin sharing adjustment. Montana-Dakota also requested an interim increase of $3.9 million annually, subject to refund. A final order is expected from the MTPSC by May 2008.

In November 2006, Montana-Dakota filed an application with the NDPSC requesting an advance determination of prudence of Montana-Dakota’s ownership interest in Big Stone II, which is expected to be completed in 2013. Hearings on the application were held in June 2007. In September 2007, Montana-Dakota informed the NDPSC that certain of the other participants in the project had withdrawn, that it was considering the impact of these withdrawals on the project and its options, and proposed that the NDPSC suspend the procedural schedule. In October 2007, Montana-Dakota proposed to supplement the record and requested that the procedural schedule be determined at a later date after consideration of optimal plant configuration by the remaining participants. A new schedule will also be set for certain regulatory proceedings applicable to the Certificate of Need filing in Minnesota applicable to the related transmission facilities.

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. Currently, the only remaining issue outstanding related to this rate change application is in regard to certain service restrictions. In May 2004, the FERC remanded this issue to an ALJ for resolution. In November 2005, the FERC issued an Order on Initial Decision affirming the ALJ’s Initial Decision regarding certain service and annual demand quantity restrictions. In April 2006, the FERC issued an Order on Rehearing denying Williston Basin’s Request for Rehearing of the FERC’s Order on Initial Decision. In April 2006, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC’s Order on Initial Decision and its Order on Rehearing. The matter concerning the service restrictions is pending resolution by the D.C. Appeals Court.

20. **Contingencies**

Litigation

Coalbed Natural Gas Operations Fidelity has been named as a defendant in, and/or certain of its operations are or have been the subject of, more than a dozen lawsuits filed in connection with its CBNG development in the Powder River Basin in Montana and Wyoming. These lawsuits were filed in federal and state courts in Montana between June 2000 and January 2007 by a number of environmental organizations, including the NPRC and the Montana Environmental Information Center, as well as the TRWUA and the Northern Cheyenne Tribe. Portions of three of the lawsuits have been transferred to the Wyoming Federal District Court. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Clean Water Act, the NEPA, the Federal Land Management Policy Act, the NHPA, the Montana State Constitution, the Montana Environmental Policy Act and the Montana Water Quality Act. The suits that remain extant include a variety of claims that state and federal government agencies violated various environmental laws that impose procedural and substantive requirements. The lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. Fidelity has intervened or moved to intervene in three lawsuits filed by other gas producers which challenge the adoption of rules by the BER related to management of water associated with CBNG production. The state of

Wyoming has filed a similar suit and Fidelity has also moved to intervene in that action.

In suits filed in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted that the BLM violated NEPA and other federal laws when approving the 2003 EIS analyzing CBNG development in southeastern Montana. The Montana Federal District Court, in February 2005, entered a ruling finding that the 2003 EIS was inadequate. The Montana Federal District Court later entered an order that would have allowed limited CBNG development in the Montana Powder River Basin pending the BLM's preparation of a SEIS. The plaintiffs appealed the decision to the Ninth Circuit because the Montana Federal District Court declined to enter an injunction enjoining all development pending completion of the SEIS. The Montana Federal District Court also declined to enter an injunction pending the appeal. In May 2005, the Ninth Circuit granted the request of the NPRC and the Northern Cheyenne Tribe and, pending appeal or further order from the Ninth Circuit, enjoined the BLM from approving any new CBNG development of federal minerals in the Montana Powder River Basin. The Ninth Circuit also enjoined Fidelity from drilling any additional federally permitted wells associated with its Montana Coal Creek Project and from constructing infrastructure to produce and transport CBNG from the Coal Creek Project's existing federal wells. The matter was briefed and argued to the Ninth Circuit in September 2005. On September 11, 2007, the Ninth Circuit affirmed the Montana Federal District Court and ruled it had correctly issued an injunction allowing up to 500 CBNG wells to be drilled each year on private, state and federal land in the Montana Powder River Basin. On October 29, 2007, in response to a motion filed by Fidelity, the Ninth Circuit lifted the 2005 injunction it had earlier issued pending the appeal. On the same date, the Ninth Circuit ordered Fidelity to respond within 21 days to the Northern Cheyenne Tribe and the NPRC’s October 16, 2007, petition to the Ninth Circuit to rehear the case.

In December 2006, the BLM issued a draft SEIS that endorses a phased-development approach to CBNG production in the Montana Powder River Basin, whereby future projects would be reviewed against four screens or filters (relating to water quality, wildlife, Native American concerns and air quality). Fidelity filed written comments on the draft SEIS asking the BLM to reconsider its proposed phased-development approach and to make numerous other changes to the draft SEIS. The public comment period on the draft SEIS concluded on May 2, 2007. The final SEIS is scheduled for release in April 2008. Fidelity cannot predict what the final terms of the SEIS will be.

In related actions in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted, among other things, that the actions of the BLM in approving Fidelity's applications for permits and the plan of development for the Badger Hills Project in Montana did not comply with applicable federal laws, including the NHPA and the NEPA. In June 2005, the Montana Federal District Court issued orders in these cases enjoining operations on Fidelity's Badger Hills Project pending the BLM's consultation with the Northern Cheyenne Tribe as to satisfaction of the applicable requirements of the NHPA and a further environmental analysis under the NEPA. Fidelity sought and obtained stays of the injunctive relief from the Montana Federal District Court and production from Fidelity’s Badger Hills Project continues. In September 2005, the Montana Federal District Court entered an Order based on a stipulation between the parties to the NPRC action that production from existing wells in Fidelity’s Badger Hills Project may continue pending preparation of a revised environmental analysis. In November 2005, the Montana Federal District Court entered an Order dismissing the Northern Cheyenne Tribe lawsuit based on the parties’ stipulation that production from existing wells in Fidelity’s Badger Hills Project could continue pending consultation with the Northern Cheyenne Tribe under the NHPA. In December 2005, Fidelity filed a Notice of Appeal of the NPRC lawsuit to the Ninth Circuit in connection with the Montana Federal District Court’s decision insofar as it found the BLM’s approval of Fidelity’s applications did not comply with applicable law.

In May 2005, the NPRC and other petitioners filed a petition with the BER to promulgate rules related to the management of water produced in association with CBNG operations. Thereafter, the BER initiated related rulemaking proceedings to consider rules that would, if promulgated, require re-injection of water produced in connection with CBNG operations, treatment of such water in the event re-injection is not feasible and amend the non-degradation policy in connection with CBNG development to include additional limitations on factors deemed harmful, thereby restricting discharges even further than under the previous standards. In March 2006, the BER issued its decision on the rulemaking petition. The BER rejected the proposed requirement of re-injection of water produced in connection with CBNG and deferred action on the proposed treatment requirement. The BER adopted the proposed amendment to the non-degradation policy. While it is possible the BER's ruling could have an adverse impact on Fidelity's operations, Fidelity believes that two five-year water discharge permits issued by the Montana DEQ in February 2006 should, assuming normal operating conditions, allow Fidelity to continue its existing CBNG operations at least through the expiration of the permits in March 2011. However, these permits are now under challenge in Montana state court by the Northern Cheyenne Tribe. Specifically, in April 2006, the Northern Cheyenne Tribe filed a complaint in the District Court of Big Horn County against the Montana DEQ seeking to set aside the two permits. The Northern Cheyenne Tribe asserted the Montana DEQ issued the permits in violation of various federal and state environmental laws. In particular, the Northern Cheyenne Tribe claimed the agency violated the Clean Water Act and the Montana Water Quality Act by failing to include in the permits conditions requiring application of the best practicable control technology currently available and by failing to impose a non-degradation policy like the one the BER adopted soon after the permit was issued. In addition, the Northern Cheyenne Tribe claimed that the actions of the Montana DEQ violated the Montana State Constitution's guarantee of a clean and healthful environment, that the Montana DEQ's related environmental assessment was invalid, that the Montana DEQ was required, but failed, to prepare an EIS and that the Montana DEQ failed to consider other alternatives to the issuance of the permits. Fidelity, the NPRC and the TRWUA have been granted leave to intervene in this proceeding. The parties have submitted cross motions for summary judgment. The motions were argued to the District Court of Big Horn County on February 28, 2007. Fidelity's discharge of water pursuant to its two permits is its primary means for managing CBNG produced water. If its permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

In a related proceeding, in July 2006, Fidelity filed a motion to intervene in a lawsuit filed in the District Court of Big Horn County by other producers. The lawsuit challenges the BER's 2006 rulemaking, which amended the non-degradation policy, as well as the BER's 2003 rulemaking procedure which first set numeric limits for certain parameters contained in water produced in connection with CBNG operations. Fidelity's motion for intervention was granted in August 2006. The parties have briefed cross motions for summary judgment and the District Court of Big Horn County heard oral argument on those motions on July 2, 2007. On October 17, 2007, the District Court of Big Horn County entered an order granting the motions filed by the BER and others and denying the motions filed by Fidelity and other producers.

Similarly, industry members have filed two lawsuits, and the state of Wyoming has filed one lawsuit, in Wyoming Federal District Court. These lawsuits challenge the EPA's failure to timely disapprove the 2006 rules. All three Wyoming lawsuits were consolidated in September 2006. Fidelity has moved to intervene in these consolidated cases. Fidelity has also intervened in a Wyoming State District Court case in support of the Governor of Wyoming's decision not to promulgate rules which were proposed by the Powder River Basin Resource Council that would have granted Wyoming's DEQ authority to regulate water quantity issues that are currently regulated by the Wyoming State Engineer.

Fidelity will continue to vigorously defend its interests in all CBNG-related lawsuits and related actions in which it is involved, including the proceedings challenging its water permits. In those cases where damage claims have been asserted, Fidelity is unable to quantify the damages sought and will be unable to do so until after the completion of discovery. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material adverse effect on Fidelity's existing CBNG operations and/or the future development of this resource in the affected regions.

Electric Operations Montana-Dakota joined with two electric generators in appealing a September 2003 finding by the ND Health Department that it may unilaterally revise operating permits previously issued to electric generating plants. Although it is doubtful that any revision of Montana-Dakota's operating permits by the ND Health Department would reduce the amount of electricity its plants could generate, the finding, if allowed to stand, could increase costs for sulfur dioxide removal and/or limit Montana-Dakota's ability to modify or expand operations at its North Dakota generation sites. Montana-Dakota and the other electric generators filed their appeal of the order in October 2003 in the Burleigh County District Court in Bismarck, North Dakota. Proceedings were stayed pending conclusion of the periodic review of sulfur dioxide emissions in the state.

In September 2005, the ND Health Department issued its final periodic review decision based on its August 2005 final air quality modeling report. The ND Health Department concluded there are no violations of the sulfur dioxide increment in North Dakota. In March 2006, the DRC filed a complaint in Colorado Federal District Court seeking to force the EPA to declare that the increment had been violated based on earlier modeling conducted by the EPA. The EPA defended against the DRC claim and filed a motion to dismiss the case. The Colorado Federal District Court has dismissed the case.

On June 6, 2007, the EPA noticed for public comment a proposed rule that would, among other things, adopt PSD increment modeling refinements that, if adopted, would operate to formally ratify the modeling techniques and conclusions contained in the September 2005 ND Health Department decision and the August 2005 final report. The public comment period on the proposed rule closed September 28, 2007. The dismissal of the case in Burleigh County District Court referenced above is dependant upon the outcome of the proposed rule.

In November 2006, the Sierra Club sent a notice of intent to file a citizen suit in federal court under the Clean Air Act to the co-owners, including Montana-Dakota, of the Big Stone Station. The suit would seek injunctive relief and monetary penalties based on the Sierra Club’s claim that three projects conducted at the Big Stone Station between 1995 and 2005 were modifications of a major source and that the Big Stone Station failed to obtain a PSD permit, conduct best available control technology analyses, and comply with other regulatory requirements for those projects. The South Dakota Department of Environment and Natural Resources reviewed and approved the three projects and the co-owners of the Big Stone Station believe that the Sierra Club’s claims are without merit. The Big Stone Station co-owners intend to vigorously defend their interests if the suit is filed.

Natural Gas Storage Based on reservoir and well pressure data and other information, Williston Basin believes that reservoir pressure (and therefore the amount of gas) in the EBSR, one of its natural gas storage reservoirs, has decreased as a result of Howell and Anadarko’s drilling and production activities in areas within and near the boundaries of the EBSR. As of September 30, 2007, Williston Basin estimated approximately 9.5 Bcf of storage gas had been diverted from the EBSR as a result of Howell and Anadarko’s drilling and production.

Williston Basin filed suit in Montana Federal District Court in January 2006, seeking to recover unspecified damages from Howell and Anadarko, and to enjoin Howell and Anadarko’s present and future production from specified wells in and near the EBSR. The Montana Federal District Court entered an Order in July 2006, dismissing the case for lack of subject matter jurisdiction. Williston Basin filed a Notice of Appeal to the Ninth Circuit in July 2006. The parties have briefed the issues. Oral argument has not yet been scheduled.

In related litigation, Howell filed suit in Wyoming State District Court against Williston Basin in February 2006 asserting that it is entitled to produce any gas that might escape from the EBSR. In August 2006, Williston Basin moved for a preliminary injunction to halt Howell and Anadarko’s production in and near the EBSR. A district court-appointed special master conducted a hearing on the motion in December 2006, and recommended denial of the motion on February 15, 2007. The Wyoming State District Court adopted the special master’s report on July 25, 2007, and denied Williston Basin’s motion for a preliminary injunction. On June 25, 2007, the Wyoming State District Court filed a motion with the Wyoming Supreme Court requesting it to answer questions of law concerning the production of Williston Basin’s storage gas by Howell and Anadarko. On July 10, 2007, the Wyoming Supreme Court issued an Order declining to answer those questions. The Wyoming State District Court has set the case for trial beginning September 29, 2008.

As noted above, Williston Basin estimates that as of September 30, 2007, Howell and Anadarko had diverted approximately 9.5 Bcf from the EBSR. Williston Basin believes Howell and Anadarko continue to divert gas from the EBSR and Williston Basin continues to monitor and analyze the situation. At trial, Williston Basin will seek recovery based on the amount of gas that has been and continues to be diverted as well as on the amount of gas that must be recovered as a result of the equalization of the pressures of various interconnected geological formations.

Williston Basin intends to vigorously defend its rights and interests in these proceedings, to assess further avenues for recovery through the regulatory process at the FERC, and to pursue the recovery of any and all economic losses it may have suffered. Williston Basin cannot predict the ultimate outcome of these proceedings.

In light of the actions of Howell and Anadarko, Williston Basin installed temporary compression at the site in 2006 in order to maintain deliverability into the transmission system. Williston Basin has leased working gas for the 2007 - 2008 heating season to supplement its cushion gas. While installation of the additional compression has provided temporary relief and the addition of leased working gas is expected to provide additional temporary relief, Williston Basin believes that the adverse physical and operational effects occasioned by the continued loss of storage gas, if left unchecked, could threaten the operation and viability of the EBSR, impair Williston Basin’s ability to comply with the EBSR certificated operating requirements mandated by the FERC and adversely affect Williston Basin’s ability to meet its contractual storage and transportation service commitments to customers.

The Company also is involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that the outcomes with respect to these other legal proceedings will not have a material adverse effect upon the Company’s financial position or results of operations.

Environmental matters

Portland Harbor Site In December 2000, MBI was named by the EPA as a Potentially Responsible Party in connection with the cleanup of a riverbed site adjacent to a commercial property site, acquired by MBI in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation of the harbor site for both the EPA and the Oregon DEQ are being recorded, and initially paid, through an administrative consent order by the LWG, a group of 10 entities, which does not include MBI or Georgia-Pacific West, Inc., the seller of the commercial property to MBI. Although the LWG originally estimated the overall remedial investigation and feasibility study would cost approximately $10 million, it is now anticipated, on the basis of costs incurred to date and delays attributable to an additional round of sampling and potential further investigative work, that such cost could increase to a total in excess of $60 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study has been completed, the EPA has decided on a strategy and a record of decision has been published. While the remedial investigation and feasibility study for the harbor site has commenced, it is expected to take several more years to complete. The development of a proposed plan and record of decision on the harbor site is not anticipated to occur until 2010, after which a cleanup plan will be undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, MBI does not believe it is a Responsible Party. In addition, MBI has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for any and all liabilities incurred in relation to the above matters, pursuant to the terms of their sale agreement. MBI has entered into an agreement tolling the statute of limitation in connection with the LWG’s potential claim for contribution to the costs of the remedial investigation and feasibility study.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above referenced administrative action.

Hardin Generating Facility In connection with the sale of the domestic independent power production business, Centennial Resources agreed to obtain an amended air permit for the Hardin Generating Facility, and to pay certain fines and penalties assessed against the facility on or prior to compliance with the amended air permit, as well as costs related to obtaining the amended air permit. The Hardin Generating Facility received four notices of violation from the Montana DEQ relating to emissions exceedances associated with startup and maintenance periods for the Hardin Generating Facility. On October 23, 2007, the Montana DEQ finalized the amended air permit. A penalty of $450,800 was paid by Centennial Resources in settlement of all four notices of violation.

Manufactured Gas Plant Sites There are two claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for soil and groundwater contamination at a site in Oregon and was received in 1995. There are potentially responsible parties in addition to Cascade that are potentially liable for cleanup of the contamination. Some of these other parties have shared in the investigation costs. It is expected that these and other potentially responsible parties will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. It is not known at this time what share of the cleanup costs will actually be borne by Cascade.

The second claim is for contamination at a site in Washington and was received in 1997. Although a preliminary investigation has concluded the site is contaminated, it appears that other property owners may have contributed to the contamination. There is currently not enough information available to estimate the potential liability associated with this claim and no formal investigation plan has been communicated to Cascade.

The Company believes that both these claims are covered by insurance. To the extent not covered by insurance, Cascade will seek recovery of contamination remediation costs through its rates.

Guarantees

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses which Petrobras may incur from certain contingent liabilities specified in the purchase agreement. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging up to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

Centennial continues to guarantee CEM's obligations under a construction contract for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. As described in Note 4, Centennial Resources sold CEM in July 2007 to Bicent Power LLC, which has provided a $10 million bank letter of credit to Centennial in support of that guarantee obligation. The guarantee, which has no fixed maximum, expires when CEM has completed its obligations under the construction contract. Construction is expected to be completed in 2008, and the warranty period associated with this project will expire one year after the date of substantial completion of the construction.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements, as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements at September 30, 2007, expire in 2007 and 2008; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. The amount outstanding by Fidelity was $498,000 and was reflected on the Consolidated Balance Sheets at September 30, 2007. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts, a conditional purchase agreement and certain other guarantees. At September 30, 2007, the fixed maximum amounts guaranteed under these agreements aggregated $465.8 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $15.8

million in 2007; $78.5 million in 2008; $341.9 million in 2009; $400,000 in 2010; $23.0 million in 2011; $1.2 million in 2012; $1.0 million, which is subject to expiration 30 days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $667,000 and was reflected on the Consolidated Balance Sheet at September 30, 2007. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, natural gas transportation agreements and other agreements that guarantee the performance of other subsidiaries of the Company. At September 30, 2007, the fixed maximum amounts guaranteed under these letters of credit aggregated $39.5 million. In 2007 and 2008, $2.8 million and $36.7 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at September 30, 2007.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands. At September 30, 2007, the fixed maximum amounts guaranteed under these agreements aggregated $25.1 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $2.2 million in 2007, $2.9 million in 2008 and $20.0 million in 2009. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was $1.7 million, which was not reflected on the Consolidated Balance Sheet at September 30, 2007, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial and Knife River have issued guarantees to third parties related to the Company's routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation with respect to the purchase of certain maintenance items, materials or lease obligations, Centennial or Knife River would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items and materials were reflected on the Consolidated Balance Sheet at September 30, 2007.

In the normal course of business, Centennial has purchased surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of September 30, 2007, approximately $423 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

The Company's strategy is to apply its expertise in energy and transportation infrastructure industries to increase market share, increase profitability and enhance shareholder value through:

- Organic growth as well as a continued disciplined approach to the acquisition of well-managed companies and properties
- The elimination of system-wide cost redundancies through increased focus on integration of operations and standardization and consolidation of various support services and functions across companies within the organization
    - The development of projects that are accretive to earnings per share and return on invested capital

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities and the issuance from time to time of debt securities and the Company's equity securities. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments. Net capital expenditures are comprised of (A) capital expenditures plus (B) acquisitions (including the issuance of the Company's equity securities, less cash acquired) less (C) net proceeds from the sale or disposition of property.

The key strategies for each of the Company's business segments, and certain related business challenges, are summarized below.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy to customers while working with them to ensure efficient usage. Both the electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment. The natural gas distribution segment also continues to pursue growth by expanding its level of energy-related services.

Challenges Both segments are subject to extensive regulation in the state jurisdictions where they conduct operations with respect to costs and permitted returns on investment as well as subject to certain operational regulations at the federal level. The ability of these segments to grow through acquisitions is subject to significant competition from other energy providers. In addition, as to the electric business, the ability of this segment to grow its service territory and customer base is affected by significant competition from other energy providers, including rural electric cooperatives.

Construction Services

Strategy Provide a competitive return on investment while operating in a competitive industry by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; focusing business development efforts on project areas that will permit higher margins; and properly managing risk. This segment continuously seeks opportunities to expand through strategic acquisitions.

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls and retention of key personnel are ongoing challenges.

Pipeline and Energy Services

Strategy Leverage the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new sources of natural gas for storage, gathering and transportation services; expansion of existing gathering and transmission facilities; and incremental expansion of pipeline capacity to allow customers access to more liquid and higher-priced markets.

Challenges Energy price volatility; natural gas basis differentials; regulatory requirements; ongoing litigation; recruitment and retention of a skilled workforce; and increased competition from other natural gas pipeline and gathering companies.

Natural Gas and Oil Production

Strategy Apply new technology and leverage existing exploration and production expertise, with a focus on operated properties, to increase production and reserves from existing leaseholds, and to seek additional reserves and production opportunities in new areas to further diversify the segment's asset base. By optimizing existing operations and taking advantage of new and incremental growth opportunities, this segment's goal is to increase both production and reserves over the long term so as to generate competitive returns on investment.

Challenges Fluctuations in natural gas and oil prices; ongoing environmental litigation and administrative proceedings; timely receipt of necessary permits and approvals; recruitment and retention of a skilled workforce; availability of drilling rigs, auxiliary equipment and industry-related field services; inflationary pressure on development and operating costs; and increased competition from other natural gas and oil companies.

Construction Materials and Mining

Strategy Focus on high growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; and continue growth through organic and acquisition opportunities. Ongoing efforts to increase margin are being pursued through the implementation of a variety of continuous improvement programs, including corporate purchasing of equipment, parts and commodities (liquid asphalt, diesel fuel, cement and other materials), negotiation of contract price escalation provisions and the utilization of national purchasing accounts. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to adequate quantities of permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its presence, through acquisition, in the higher-margin materials business (rock, sand, gravel, liquid asphalt, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Price volatility with respect to, and availability of, raw materials such as liquid asphalt, diesel fuel and cement; recruitment and retention of a skilled workforce; and management of fixed price construction contracts, which are particularly vulnerable to volatility of these energy and material prices. In some of our markets, we are challenged to mitigate severe effects caused by the continued decline in the residential construction sector, as well as the level and timing of federal and state transportation funding. A greater emphasis on commercial construction and cost containment should partially mitigate the effects.

Independent Power Production

Overall business challenges for this segment include the risks and uncertainties associated with foreign currency fluctuation and political risk in the countries where this segment does business.

For further information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see Part II, Item 1A – Risk Factors, as well as Part I, Item 1A – Risk Factors in the 2006 Annual Report. For further information on each segment's key growth strategies, projections and certain assumptions, see Prospective Information. For information pertinent to various commitments and contingencies, see Notes to Consolidated Financial Statements.

Earnings Overview

The following table summarizes the contribution to consolidated earnings by each of the Company's businesses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(Dollars in millions, where applicable)			
Electric	$ 5.7	$ 5.7	$ 13.0	$ 10.0
Natural gas distribution	(4.5)	(2.3)	1.1	.4
Construction services	13.7	8.3	33.9	23.4
Pipeline and energy services	9.2	8.7	21.1	19.5
Natural gas and oil production	33.2	35.0	99.0	107.2
Construction materials and mining	50.4	52.5	66.1	69.0

Independent power production		(3.5)		(1.3)		(7.6)		(2.8)
Other		.1		.3		.8		.8
Earnings before discontinued operations		104.3		106.9		227.4		227.5
Income from discontinued operations, net of tax		96.8		1.4		109.5		5.2
Earnings on common stock	$	201.1	$	108.3	$	336.9	$	232.7
Earnings per common share – basic:								
Earnings before discontinued operations	$	.57	$	.59	$	1.25	$	1.26
Discontinued operations, net of tax		.53		.01		.60		.03
Earnings per common share – basic	$	1.10	$	.60	$	1.85	$	1.29
Earnings per common share – diluted:								
Earnings before discontinued operations	$	.57	$	.59	$	1.24	$	1.26
Discontinued operations, net of tax		.53		.01		.60		.03
Earnings per common share – diluted	$	1.10	$	.60	$	1.84	$	1.29
Return on average common equity for the 12 months ended						18.7%		15.7%

Three Months Ended September 30, 2007 and 2006 Consolidated earnings for the quarter ended September 30, 2007, increased $92.8 million from the comparable period largely due to:

- Increased income from discontinued operations, net of tax, largely due to the gain on the sale of the Company’s domestic independent power production assets and earnings related to an electric generating facility construction project
- Partially offset by lower earnings of $2.6 million from continuing operations

Nine Months Ended September 30, 2007 and 2006 Consolidated earnings for the nine months ended September 30, 2007, increased $104.2 million, primarily due to increased income from discontinued operations, net of tax, largely due to the gain on the sale of the Company’s domestic independent power production assets, earnings related to an electric generating facility construction project and the absence in 2007 of depreciation expense related to assets held for sale.

FINANCIAL AND OPERATING DATA

The following tables contain key financial and operating statistics for each of the Company's businesses.

Electric

		Three Months Ended September 30,				Nine Months Ended September 30,		
		2007		2006		2007		2006
		(Dollars in millions, where applicable)						
Operating revenues	$	54.0	$	53.2	$	145.7	$	139.1
Operating expenses:								
Fuel and purchased power		20.3		19.1		52.9		51.2
Operation and maintenance		16.0		16.3		45.6		46.0
Depreciation, depletion and amortization		5.7		5.4		16.9		15.9
Taxes, other than income		2.1		2.1		6.4		6.4
		44.1		42.9		121.8		119.5
Operating income		9.9		10.3		23.9		19.6
Earnings	$	5.7	$	5.7	$	13.0	$	10.0
Retail sales (million kWh)		703.5		652.1		1,945.5		1,828.1
Sales for resale (million kWh)		39.2		172.3		130.4		423.9
Average cost of fuel and purchased power per kWh	$	.027	$	.022	$	.025	$	.022

Three Months Ended September 30, 2007 and 2006 Electric earnings were unchanged from the comparable prior period. Lower sales for resale margins and volumes were largely offset by higher retail sales volumes and margins.

Nine Months Ended September 30, 2007 and 2006 Electric earnings increased $3.0 million largely due to higher retail sales margins and volumes and higher sales for resale margins, partially offset by lower sales for resale volumes.

Natural Gas Distribution

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(Dollars in millions, where applicable)			
Operating revenues	$ 90.7	$ 31.4	$ 280.2	$ 229.5
Operating expenses:				
Purchased natural gas sold	53.3	20.7	193.9	182.5
Operation and maintenance	26.6	11.0	57.8	35.7
Depreciation, depletion and amortization	7.1	2.5	12.0	7.3
Taxes, other than income	5.9	1.4	9.1	4.5
	92.9	35.6	272.8	230.0
Operating income (loss)	(2.2)	(4.2)	7.4	(.5)
Earnings (loss)	$ (4.5)	$ (2.3)	$ 1.1	$ .4
Volumes (MMdk):				
Sales	7.2	3.1	28.4	21.9
Transportation	22.7	2.6	29.0	9.8
Total throughput	29.9	5.7	57.4	31.7
Degree days (% of normal)*				
Montana-Dakota	71%	94%	93%	83%
Cascade	102%	---	102%	---
Average cost of natural gas, including transportation, per dk**				
Montana-Dakota	$ 5.15	$ 6.67	$ 6.45	$ 8.32
Cascade	$ 7.60	---	$ 7.60	---

* Degree days are a measure of the daily temperature-related demand for energy for heating.

** Regulated natural gas sales only.

Note: Cascade was acquired on July 2, 2007. For further information, see Note 3.

Three Months Ended September 30, 2007 and 2006 The natural gas distribution business experienced a seasonal loss of $4.5 million in the third quarter of 2007 compared to a loss of $2.3 million in the third quarter of 2006. The increase in loss was due to a seasonal loss of $2.4 million (after tax) at Cascade which was acquired since the comparable prior period.

Nine Months Ended September 30, 2007 and 2006 Earnings at the natural gas distribution business increased $700,000 due to:

- Higher retail sales margins, including increased retail sales volumes resulting from 13 percent colder weather than last year
- Decreased operation and maintenance expense (excluding Cascade) of $1.1 million (after tax), including the absence in 2007 of the 2006 early retirement program costs
- Higher nonregulated energy-related services of $700,000 (after tax)

Largely offsetting these increases was the third quarter seasonal loss of $2.4 million (after tax) at Cascade which was acquired since the comparable prior period.

Construction Services

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions)			
Operating revenues	$ 293.3	$ 262.3	$ 793.9	$ 729.3
Operating expenses:				
Operation and maintenance	258.1	236.8	700.4	656.2
Depreciation, depletion and amortization	3.5	3.6	10.5	11.0
Taxes, other than income	8.5	6.6	24.8	19.5
	270.1	247.0	735.7	686.7
Operating income	23.2	15.3	58.2	42.6
Earnings	$ 13.7	$ 8.3	$ 33.9	$ 23.4

Three Months Ended September 30, 2007 and 2006 Construction services earnings increased $5.4 million due to:

- Higher construction margins and workloads of $4.6 million (after tax), largely in the Central and Southwest regions, including industrial-related work
- Increased equipment sales and rentals

Nine Months Ended September 30, 2007 and 2006 Construction services earnings increased $10.5 million due to:

- Higher construction margins and workloads of $9.1 million (after tax), largely in the Central and Southwest regions, including industrial-related work
- Increased equipment sales and rentals

Pipeline and Energy Services

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(Dollars in millions)			
Operating revenues:				
Pipeline	$ 34.1	$ 27.7	$ 88.6	$ 74.5
Energy services	68.4	76.1	239.2	258.3
	102.5	103.8	327.8	332.8
Operating expenses:				
Purchased natural gas sold	60.9	69.0	216.3	236.1
Operation and maintenance	17.1	12.8	47.7	38.4
Depreciation, depletion and amortization	5.4	4.9	16.1	14.9
Taxes, other than income	2.7	2.5	8.1	7.6
	86.1	89.2	288.2	297.0
Operating income	16.4	14.6	39.6	35.8
Income from continuing operations	9.2	8.7	21.1	19.5
Income (loss) from discontinued operations, net of tax	.2	(1.6)	.3	(2.2)
Earnings	$ 9.4	$ 7.1	$ 21.4	$ 17.3
Transportation volumes (MMdk):				
Montana-Dakota	6.6	7.5	21.7	22.6
Other	33.5	29.3	83.7	75.4
	40.1	36.8	105.4	98.0
Gathering volumes (MMdk)	23.5	21.9	68.2	64.8

Three Months Ended September 30, 2007 and 2006 Pipeline and energy services experienced an increase in earnings of $2.3 million due to:

- Increased income from discontinued operations of $1.8 million (after tax), related to Innovatum. For further information, see Note 4.
- Higher transportation and gathering volumes

Nine Months Ended September 30, 2007 and 2006 Pipeline and energy services experienced an increase in earnings of $4.1 million due to:

- Higher transportation and gathering volumes of $3.7 million (after tax)
- Increased income from discontinued operations of $2.5 million (after tax), related to Innovatum, as previously discussed
- Higher storage services revenue of $2.2 million (after tax)
- Higher gathering rates of $1.1 million (after tax)

Partially offsetting these increases were higher operation and maintenance expenses, primarily related to the natural gas storage litigation and higher material and payroll costs. For more information regarding natural gas storage litigation, see Note 20.

The decrease in energy services revenue and purchased natural gas sold reflects the effect of lower natural gas prices.

Natural Gas and Oil Production

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(Dollars in millions, where applicable)			
Operating revenues:				
Natural gas	$ 86.4	$ 89.1	$ 276.4	$ 281.7
Oil	36.5	31.6	92.3	78.0
Other	.2	1.8	.4	5.3
	123.1	122.5	369.1	365.0
Operating expenses:				
Purchased natural gas sold	---	1.5	.3	5.2
Operation and maintenance:				
Lease operating costs	17.6	14.0	48.7	38.3
Gathering and transportation	5.3	4.5	14.9	13.9
Other	8.9	7.2	26.3	23.9
Depreciation, depletion and amortization	33.2	27.7	92.7	78.1
Taxes, other than income:				
Production and property taxes	8.5	8.5	26.7	26.4
Other	.1	.2	.6	.7
	73.6	63.6	210.2	186.5
Operating income	49.5	58.9	158.9	178.5
Earnings	$ 33.2	$ 35.0	$ 99.0	$ 107.2
Production:				
Natural gas (MMcf)	15,865	15,603	46,536	46,207
Oil (MBbls)	565	554	1,710	1,475
Average realized prices (including hedges):				
Natural gas (per Mcf)	$ 5.45	$ 5.71	$ 5.94	$ 6.10

Oil (per barrel)	$	64.54	$	57.01	$	53.94	$	52.90
Average realized prices (excluding hedges):								
Natural gas (per Mcf)	$	4.51	$	5.13	$	5.35	$	5.72
Oil (per barrel)	$	64.64	$	57.69	$	53.98	$	53.99
Production costs, including taxes, per net equivalent Mcf:								
Lease operating costs	$	.91	$	.74	$	.86	$	.70
Gathering and transportation		.28		.23		.26		.25
Production and property taxes		.44		.45		.47		.48
	$	1.63	$	1.42	$	1.59	$	1.43

Three Months Ended September 30, 2007 and 2006 The natural gas and oil production business experienced a decrease in earnings of $1.8 million due to:

- Increased depreciation, depletion and amortization expense of $3.3 million (after tax) due to higher depletion rates and increased production
- Higher lease operating expense of $2.2 million (after tax)
- Lower average realized natural gas prices of 5 percent

Partially offsetting these decreases were:

- Income tax benefit of $3.1 million due to lower effective state income tax rates
- Higher average realized oil prices of 13 percent
- Increased natural gas production of 2 percent and increased oil production of 2 percent, largely due to increased drilling activity at existing properties

Nine Months Ended September 30, 2007 and 2006 The natural gas and oil production business experienced an $8.2 million decrease in earnings due to:

- Increased depreciation, depletion and amortization expense of $9.1 million (after tax) due to higher depletion rates and increased production
- Higher lease operating expense of $6.5 million (after tax), largely acquisition and CBNG-related costs, as well as increased costs at nonoperated properties
- Lower average realized natural gas prices of 3 percent
- Increased general and administrative expense of $1.5 million (after tax), partially due to higher payroll-related costs

Partially offsetting these decreases were:

- Increased oil production of 16 percent resulting from the May 2006 Big Horn acquisition, as well as from the South Texas properties
- Income tax benefit of $3.1 million, as previously described
- Higher average realized oil prices of 2 percent
- Increased natural gas production of 1 percent

Construction Materials and Mining

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2007		2006		2007		2006
	(Dollars in millions)							
Operating revenues	$	639.6	$	667.6	$	1,322.7	$	1,386.2
Operating expenses:								

Operation and maintenance	519.7	546.9	1,101.4	1,167.1
Depreciation, depletion and amortization	23.2	22.6	69.1	64.8
Taxes, other than income	11.8	10.0	33.4	30.3
	554.7	579.5	1,203.9	1,262.2
Operating income	84.9	88.1	118.8	124.0
Earnings	$ 50.4	$ 52.5	$ 66.1	$ 69.0
Sales (000's):				
Aggregates (tons)	11,769	14,961	27,665	34,386
Asphalt (tons)	3,330	3,669	5,435	6,358
Ready-mixed concrete (cubic yards)	1,328	1,420	3,046	3,391

Three Months Ended September 30, 2007 and 2006 Earnings at the construction materials and mining business decreased $2.1 million from the comparable prior period due to:

- Lower margins from existing operations of $6.2 million (after tax), primarily related to lower sale volumes resulting from the slow down in certain residential housing markets, partially offset by higher realized prices as well as higher margins from asphalt and related products

Partially offsetting the decrease were:

- Decreased general and administrative expense of $2.2 million (after tax), partially due to lower payroll-related costs
- Earnings from companies acquired since the comparable prior period which contributed 4 percent to earnings for the current quarter

Nine Months Ended September 30, 2007 and 2006 Earnings at the construction materials and mining business decreased $2.9 million due to:

- Lower margins from existing operations of $5.6 million, as previously discussed
- Higher depreciation, depletion and amortization expense of $1.8 million (after tax), primarily due to higher property, plant and equipment balances

Partially offsetting these decreases were:

- Earnings from companies acquired since the comparable prior period which contributed 3 percent to earnings for the nine months ended September 30, 2007
- Decreased general and administrative expense of $2.0 million (after tax), primarily due to lower payroll-related costs

Independent Power Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(Dollars in millions)			
Operating revenues	$ ---	$ ---	$ ---	$ ---
Operating expenses:				
Operation and maintenance	2.1	1.7	5.7	5.8
Depreciation, depletion and amortization	---	---	.2	.1
Taxes, other than income	.1	.1	.2	.1
	2.2	1.8	6.1	6.0
Operating loss	(2.2)	(1.8)	(6.1)	(6.0)
Loss from continuing operations	(3.5)	(1.3)	(7.6)	(2.8)

Income from discontinued operations, net of tax	96.6	3.0	109.2	7.4
Earnings	$ 93.1	$ 1.7	$ 101.6	$ 4.6

Three Months Ended September 30, 2007 and 2006 Earnings at the independent power production business increased $91.4 million due to the following:

- Increased income from discontinued operations, net of tax, of $93.6 million largely due to:
  - o An $85.4 million (after tax) gain on the sale of the Company's domestic independent power production assets, excluding Hartwell
  - o Earnings of $10.5 million (after tax) related to an electric generating station construction project in Hobbs, New Mexico

Partially offsetting these increases was:

- Higher loss from continuing operations, net of tax, of $2.2 million, largely due to:
  - o An income tax adjustment of $10.0 million associated with the anticipated repatriation of profits from Brazilian operations as discussed in Note 16, partially offset by the gain of $6.1 million (after tax) related to the sale of Hartwell

Nine Months Ended September 30, 2007 and 2006 Earnings at the independent power production business increased $97.0 million due to:

- Increases previously discussed in the three months ended September 30, 2007 and 2006
- The absence in 2007 of depreciation expense related to assets held for sale

Other and Intersegment Transactions
Amounts presented in the preceding tables will not agree with the Consolidated Statements of Income due to the Company's other operations and the elimination of intersegment transactions. The amounts relating to these items are as follows:

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions)			
Other:				
Operating revenues	$ 2.4	$ 1.8	$ 7.3	$ 5.9
Operation and maintenance	2.4	1.2	6.3	4.3
Depreciation, depletion and amortization	.3	.3	.8	.8
Taxes, other than income	---	.1	---	.1
Intersegment transactions:				
Operating revenues	$ 60.3	$ 69.0	$ 231.5	$ 249.1
Purchased natural gas sold	53.3	62.6	210.5	228.8
Operation and maintenance	7.0	6.4	21.0	20.3

For further information on intersegment eliminations, see Note 17.

PROSPECTIVE INFORMATION
The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for each of the Company's businesses. Many of these highlighted points are "forward-looking statements." There is no assurance that the Company's projections, including estimates for growth and changes in revenues and earnings, will in fact be achieved. Please refer to assumptions contained in this section, as

well as the various important factors listed in Part II, Item 1A – Risk Factors, as well as Part I, Item 1A – Risk Factors in the 2006 Annual Report. Changes in such assumptions and factors could cause actual future results to differ materially from targeted growth, revenue and earnings projections.

MDU Resources Group, Inc.

- Earnings per common share for 2007, diluted, are projected in the range of $2.20 to $2.35. The earnings per share guidance range includes the third quarter gain of $91.5 million (after tax) on the sale of the domestic independent power production assets, and earnings from discontinued operations.

- Long-term compound annual growth goals on earnings per share from operations are in the range of 7 percent to 10 percent

Electric

- The Company is analyzing potential projects for accommodating load growth and replacing an expired purchased power contract with company-owned generation, which will add to base-load capacity and rate base. For further information, see Note 19.

- The Company is in the process of constructing approximately 20 MW of wind-powered electric generation near Baker, Montana. The project includes 13, 1.5-MW wind turbines at a project cost of approximately $37 million. The project is expected to be rate based and on line in late 2007.

- On July 12, 2007, Montana-Dakota filed an electric rate case with the MTPSC, as discussed in Note 19

Natural gas distribution

- This business continues to pursue expansion of energy-related services and expects continued strong customer growth in Washington and Oregon

Construction services

- The Company anticipates higher average margins in 2007 as compared to 2006, and continues to focus on costs and efficiencies to improve margins

- Work backlog as of September 30, 2007, is approximately $826 million compared to backlog of $505 million at September 30, 2006

Pipeline and energy services

- Based on anticipated demand, additional incremental expansions to the Grasslands Pipeline are forecasted over the next few years. An expansion to 138,000 Mcf per day was completed on November 1, 2007. Through additional compression, the pipeline capacity could ultimately reach 200,000 Mcf per day.

- In 2007, total gathering and transportation throughput is expected to increase approximately 6 percent over 2006 record levels

Natural gas and oil production

- Long-term compound annual growth goals for production are in the range of 7 percent to 10 percent

- In 2007, the Company expects a combined natural gas and oil production increase of approximately 4 percent

- The Company expects to drill approximately 250 wells in 2007, which reflects the commingling of multiple coal seams into a single well bore. Commingling reduces the number of wells required to be drilled while accessing the same reserve potential. Currently this segment’s net combined natural gas and oil production is approximately 210,000 Mcf equivalent to 220,000 Mcf equivalent per day.

- Earnings guidance reflects estimated natural gas prices for November through December 2007 as follows:

Index*	**Price Per Mcf**
Ventura	$6.25 to $6.75
NYMEX	$6.75 to $7.25
CIG	$4.00 to $4.50

* Ventura is an index pricing point related to Northern Natural Gas Co.'s system; CIG is an index pricing point related to Colorado Interstate Gas Co.'s system

During 2006 and through September 30, 2007, more than three-fourths of the Company's natural gas production was priced at non-NYMEX prices, the majority of which was at Ventura pricing.

- Earnings guidance reflects estimated NYMEX crude oil prices for October through December 2007 in the range of $73 to $78 per barrel

- The Company has hedged approximately 35 percent to 40 percent of its estimated natural gas production and approximately 5 percent to 10 percent of its estimated oil production for the last three months of 2007. For 2008, the Company has hedged approximately 30 percent to 35 percent of its estimated natural gas production and less than 5 percent of its estimated oil production. The hedges that are in place as of November 2, 2007, are summarized in the following chart:

Commodity	**Index***	**Period Outstanding**	**Forward Notional Volume (MMBtu/Bbl)**	**Price Swap or Costless Collar Floor-Ceiling (Per MMBtu/Bbl)**
Natural Gas	Ventura	10/07	232,500	$7.16
Natural Gas	Ventura	10/07 - 12/07	460,000	$8.00-$11.91
Natural Gas	Ventura	10/07 - 12/07	230,000	$8.00-$11.80
Natural Gas	Ventura	10/07 - 12/07	230,000	$8.00-$11.75
Natural Gas	Ventura	10/07 - 12/07	460,000	$7.50-$10.55
Natural Gas	CIG	10/07 - 12/07	460,000	$7.40
Natural Gas	CIG	10/07 - 12/07	460,000	$7.405
Natural Gas	Ventura	10/07 - 12/07	368,000	$8.25-$10.80
Natural Gas	CIG	10/07 - 12/07	230,000	$7.50-$9.12
Natural Gas	Ventura	10/07 - 12/07	460,000	$8.29
Natural Gas	Ventura	10/07 - 12/07	460,000	$7.85-$9.70
Natural Gas	Ventura	10/07 - 12/07	920,000	$7.67
Natural Gas	NYMEX	10/07 - 12/07	460,000	$7.50-$8.50
Natural Gas	Ventura	11/07 - 3/08	1,520,000	$8.00-$8.75
Natural Gas	Ventura	11/07 - 3/08	608,000	$9.01
Natural Gas	Ventura	1/08 - 3/08	910,000	$9.35
Natural Gas	CIG	1/08 - 3/08	910,000	$7.00-$7.79
Natural Gas	CIG	1/08 - 3/08	910,000	$8.06
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$7.00-$8.05
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$7.00-$8.06
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$7.45
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$7.50-$8.70
Natural Gas	Ventura	4/08 - 10/08	1,070,000	$8.005

Natural Gas	Ventura	1/08 - 12/08	1,830,000	$7.00-$8.45
Natural Gas	Ventura	1/08 - 12/08	1,830,000	$7.50-$8.34
Natural Gas	Ventura	1/08 - 12/08	3,294,000	$8.55
Natural Gas	NYMEX	1/08 - 12/08	1,830,000	$7.50-$10.15
Natural Gas	CIG	4/08 - 12/08	1,375,000	$6.75-$7.04
Natural Gas	CIG	4/08 - 12/08	1,375,000	$6.35
Natural Gas	CIG	4/08 - 12/08	1,375,000	$6.41
Natural Gas	Ventura	11/08 - 12/08	610,000	$8.85
Crude Oil	NYMEX	10/07 - 12/07	39,100	$75.25
Crude Oil	NYMEX	1/08 - 12/08	73,200	$67.50-$78.70

* Ventura is an index pricing point related to Northern Natural Gas Co.'s system; CIG is an index pricing point related to Colorado Interstate Gas Co.'s system

Construction materials and mining

- The Company anticipates margins in 2007 to be comparable to 2006

- Work backlog as of September 30, 2007, was approximately $520 million compared to $594 million at September 30, 2006

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Note 11, which is incorporated by reference.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

The Company's critical accounting policies involving significant estimates include impairment testing of long-lived assets and intangibles, impairment testing of natural gas and oil production properties, revenue recognition, purchase accounting, asset retirement obligations, and pension and other postretirement benefits. There were no material changes in the Company's critical accounting policies involving significant estimates from those reported in the 2006 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2006 Annual Report.

LIQUIDITY AND CAPITAL COMMITMENTS

Cash flows

Operating activities Net income before depreciation, depletion and amortization is a significant contributor to cash flows from operating activities. The changes in cash flows from operating activities generally follow the results of operations as discussed in Financial and Operating Data and also are affected by changes in working capital.

Cash flows provided by operating activities in the first nine months of 2007 decreased $75.7 million from the comparable 2006 period, the result of increased cash used related to discontinued operations of $65.0 million, largely due to an increase in quarterly income tax payments due to the gain on the sale of the domestic independent power production assets. In addition, cash used for working capital requirements increased $34.5 million. Partially offsetting the decrease in cash flows from operating activities were higher depreciation, depletion and amortization expense of $25.4 million and higher deferred income taxes of $14.8 million.

Investing activities Cash flows used by investing activities in the first nine months of 2007 decreased $461.0 million compared to the comparable 2006 period, the result of:

- An increase in cash flows provided by discontinued operations of $588.3 million, primarily the result of the sale of the domestic independent power production assets in the third quarter of 2007
- An increase in cash flows from investments of $59.2 million, largely due to the absence in 2007 of the 2006 acquisition of the Brazilian Transmission Lines

- Increased proceeds from the sale of equity method investments of $56.2 million, primarily the result of the sale of the Trinity Generating Facility in the first quarter of 2007 and Hartwell in the third quarter of 2007

Partially offsetting the increase in cash flows from investing activities were:

- An increase in cash flows used for acquisitions, net of cash acquired, of $230.1 million, largely the result of the Cascade acquisition, partially offset by the absence in 2007 of the 2006 Big Horn acquisition at the natural gas and oil production business

Financing activities Cash flows used in financing activities in the first nine months of 2007 increased $329.1 million compared to the comparable 2006 period, primarily the result of a decrease in the issuance of long-term debt of $309.5 million, and higher repayments of long-term debt of $20.4 million. Also reflected in the cash flows from financing activities was the issuance and subsequent repayment of short-term borrowings of $310.0 million from the term loan agreement entered into in connection with the funding of the Cascade acquisition.

Defined benefit pension plans

Cascade has a qualified noncontributory defined benefit pension plan covering substantially all union employees and salaried employees hired before September 30, 2003. Plan assets consist of investments in equity and fixed income securities. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the Cascade pension plan. Actuarial assumptions include assumptions about the discount rate and expected return on plan assets as determined by the Company within certain guidelines. At September 30, 2006, the Cascade pension plan's accumulated benefit obligation exceeded the plan's assets by approximately $6.7 million. Cascade's pension expense is currently projected to be approximately $500,000 to $600,000 for the last six months of 2007. Funding for the Cascade pension plan is actuarially determined.

Except for changes related to the acquisition of Cascade as previously discussed, there were no other significant changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2006 Annual Report. For further information, see Note 18 and Part II, Item 7 in the 2006 Annual Report.

Capital expenditures

Net capital expenditures for the first nine months of 2007 were approximately $906 million and are estimated to be approximately $1.16 billion for 2007. Both of these amounts include the outstanding indebtedness of Cascade at the time of acquisition and exclude proceeds from the sale of the domestic independent power production assets. Estimated capital expenditures include those for:

- Completed acquisitions
- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering projects
- Further enhancement of natural gas and oil production and reserve growth
- Power generation opportunities, including certain costs for additional electric generating capacity
- Other growth opportunities

Approximately 48 percent of estimated 2007 net capital expenditures referred to previously are associated with completed acquisitions, primarily related to the acquisition of Cascade. The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimated 2007 capital expenditures referred to previously. It is anticipated that all of the funds required for capital expenditures will be met from various sources, including internally generated funds; the Company's credit facilities, as described below; and through the issuance of long-term debt and the Company's equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at September 30, 2007.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling $125 million (with provision for an increase, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement at September 30, 2007. The credit agreement supports the Company's $100 million commercial paper program. Under the Company's commercial paper program, $25.2 million was outstanding at September 30, 2007. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires in June 2011).

The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Minor fluctuations in the Company's credit ratings have not limited, nor would they be expected to limit, the Company's ability to access the capital markets. In the event of a minor downgrade, the Company may experience a nominal basis point increase in overall interest rates with respect to its cost of borrowings. If the Company were to experience a significant downgrade of its credit ratings, it may need to borrow under its credit agreement.

Prior to the maturity of the credit agreement, the Company expects that it will negotiate the extension or replacement of this agreement. If the Company is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility became too expensive, which the Company does not currently anticipate, the Company would seek alternative funding.

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of the Company's credit agreement, see Part II, Item 7, in the 2006 Annual Report. The Company was in compliance with these covenants and met the required conditions at September 30, 2007.

In connection with the funding of the Cascade acquisition, on June 29, 2007, the Company entered into a term loan agreement with Wells Fargo Bank, National Association, providing for a commitment amount of $310 million. The Company borrowed $310 million under this agreement on July 2, 2007. On July 11, 2007, and August 14, 2007, the Company paid down $220 million and $5 million, respectively, of the outstanding principal balance. In addition, on August 14, 2007 and August 28, 2007, the Company received $50 million and $35 million, respectively, from the repayment of an intercompany loan with MDU Energy Capital. The Company, in turn, repaid the outstanding principal balance of the term loan indebtedness that it incurred to fund the acquisition of Cascade. The term loan agreement terminated on August 28, 2007.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Mortgage. Generally, those restrictions require the Company to fund $1.43 of unfunded property or use $1.00 of refunded bonds for each dollar of indebtedness incurred under the Indenture and, in some cases, to certify to the trustee that annual earnings (pretax and before interest charges), as defined in the Indenture, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the tests, as of September 30, 2007, the Company could have issued approximately $510 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred dividends was 6.2 times and 6.4 times for the 12 months ended September 30, 2007 and December 31, 2006, respectively. Additionally, the Company's first mortgage bond interest coverage was 39.9 times and 26.0 times for the 12 months ended September 30, 2007 and December 31, 2006, respectively. Common stockholders' equity as a percent of total capitalization (including long-term debt due within one year) was 66 percent and 63 percent at September 30, 2007 and December 31, 2006, respectively.

The Company has repurchased, and may from time to time seek to repurchase, outstanding first mortgage bonds through open market purchases or privately negotiated transactions. The Company will evaluate any such transactions in light of then existing market conditions, taking into account its liquidity and prospects for future access to capital. As of September 30, 2007, the Company had $50.5 million of first mortgage bonds outstanding, $30.0 million of which were held by the Indenture trustee for the benefit of the senior note holders. At such time as the aggregate principal amount of the Company’s outstanding first mortgage bonds, other than those held by the Indenture trustee, is $20.0 million or less, the Company would have the ability, subject to satisfying certain specified conditions, to require that any debt issued under its Indenture become unsecured and rank equally with all of the Company’s other unsecured and unsubordinated debt (as of September 30, 2007, the only such debt outstanding under the Indenture was $30.0 million in aggregate principal amount of the Company’s 5.98% Senior Notes due in 2033).

The Company has entered into a Sales Agency Financing Agreement, as amended June 25, 2007, with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 3,000,000 shares of the Company’s common stock, par value $1.00 per share, together with preference share purchase rights appurtenant thereto. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement, which terminates on December 1, 2008. Proceeds from the sale of shares of common stock under the agreement are expected to be used for corporate development purposes and other general corporate purposes. The offering would be made pursuant to the Company’s shelf registration statement on Form S-3, as amended, which became effective on September 26, 2003, as supplemented by a prospectus supplement, dated June 28, 2007, filed with the SEC pursuant to Rule 424(b) under the Securities Act of 1933, as amended. The Company has not issued any stock under the Sales Agency Financing Agreement through September 30, 2007.

MDU Energy Capital, LLC On August 14, 2007, MDU Energy Capital entered into a $125 million master shelf agreement (dated as of August 9, 2007), and borrowed $50 million under the agreement. On August 28, 2007, MDU Energy Capital borrowed an additional $35 million under the master shelf agreement. MDU Energy Capital used the proceeds from the borrowings to repay a short-term intercompany loan from the Company applicable to the acquisition of Cascade, as previously discussed.

The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (i) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (ii) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the twelve month period ended each fiscal quarter (commencing with the fiscal quarter ended September 30, 2007), to be greater than 1.5 to 1. MDU Energy Capital was in compliance with these covenants and met the required conditions at September 30, 2007. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement). MDU Energy Capital may incur additional indebtedness under the master shelf agreement, up to a total of $125 million, until the earlier of August 14, 2010, or such time as the agreement is terminated by either of the parties thereto.

Cascade Natural Gas Corporation Cascade has a $60 million bank revolving credit agreement which expires on January 1, 2008. The Company is currently in negotiations regarding a renewal of this agreement. Cascade also has a $20 million uncommitted line of credit which may be terminated by the bank or Cascade at any time. There were no outstanding borrowings under the Cascade credit agreements at September 30, 2007. As of September 30, 2007, there were outstanding letters of credit, as discussed in Note 20, of which $1.9 million reduced amounts available under the $60 million credit agreement.

In order to borrow under Cascade's $60 million bank revolving credit agreement, Cascade must be in compliance with the applicable covenants and certain other conditions. This includes a covenant not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Also included is a covenant that requires Cascade's fixed charges coverage ratio to be greater than 1.2 to 1 on any given date, as measured for the prior four fiscal quarters. Cascade was in compliance with these covenants and met the required conditions at September 30, 2007.

Centennial Energy Holdings, Inc. Centennial has two revolving credit agreements with various banks and institutions totaling $425 million with certain provisions allowing for increased borrowings. These credit agreements support Centennial's $400 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements or the Centennial commercial paper program at September 30, 2007. Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings (supported by Centennial credit agreements). One of these credit agreements is for $400 million, which includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of $450 million and expires on August 26, 2010. The second agreement is an uncommitted line for $25 million, and may be terminated by the bank at any time. As of September 30, 2007, there were outstanding letters of credit, as discussed in Note 20, of which $27.2 million reduced amounts available under these agreements.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $550 million. Under the terms of the master shelf agreement, $420.0 million was outstanding at September 30, 2007. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009. To meet potential future financing needs, Centennial may pursue other financing arrangements, including private and/or public financing.

Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Minor fluctuations in Centennial's credit ratings have not limited, nor would they be expected to limit, Centennial's ability to access the capital markets. In the event of a minor downgrade, Centennial may experience a nominal basis point increase in overall interest rates with respect to its cost of borrowings. If Centennial were to experience a significant downgrade of its credit ratings, it may need to borrow under its committed bank lines.

Prior to the maturity of the Centennial credit agreements, Centennial expects that it will negotiate the extension or replacement of these agreements, which provide credit support to access the capital markets. In the event Centennial was unable to successfully negotiate these agreements, or in the event the fees on such facilities became too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

In order to borrow under Centennial's credit agreements and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions. For more information on the covenants and certain other conditions for the $400 million credit agreement and the master shelf agreement, see Part II, Item 7, in the 2006 Annual Report. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at September 30, 2007.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default. Certain of Centennial's financing agreements and Centennial's practice limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company Williston Basin has an uncommitted long-term master shelf agreement that allows for borrowings of up to $100 million. Under the terms of the master shelf agreement, $80.0 million was outstanding at September 30, 2007. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2008.

In order to borrow under its uncommitted long-term master shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions. For more information on the covenants and certain other conditions for the uncommitted long-term master shelf agreement, see Part II, Item 7, in the 2006 Annual Report. Williston Basin was in compliance with these covenants and met the required conditions at September 30, 2007.

Off balance sheet arrangements

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses that Petrobras may incur from certain contingent liabilities specified in the purchase agreement. For more information, see Note 20.

Centennial continues to guarantee CEM's obligations under a construction contract for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. For more information, see Note 20.

Contractual obligations and commercial commitments

At September 30, 2007, the Company's contractual obligations related to long-term debt, estimated interest payments, operating leases and purchase commitments (for the twelve months ended September 30, of each year listed in the table below) were as follows:

	2008	2009	2010	2011	2012	Thereafter	Total
				(In millions)			
Long-term debt	$ 132.0	$ 87.7	$ 22.8	$ 92.6	$ 80.4	$ 863.2	$ 1,278.7
Estimated interest payments*	70.4	63.2	60.5	57.2	53.1	351.2	655.6
Operating leases	16.4	13.9	12.6	10.5	7.2	49.5	110.1
Purchase commitments	508.9	332.0	253.7	172.1	121.8	342.3	1,730.8
	$ 727.7	$ 496.8	$ 349.6	$ 332.4	$ 262.5	$ 1,606.2	$ 3,775.2

* *Estimated interest payments are calculated based on the applicable rates and payment dates.*

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to the impact of market fluctuations associated with commodity prices, interest rates and foreign currency. The Company has policies and procedures to assist in controlling these market risks and utilizes derivatives to manage a portion of its risk.

Commodity price risk

Fidelity utilizes derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on its forecasted sales of natural gas and oil production. Cascade utilizes derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas on its forecasted purchases of natural gas. At September 30, 2007, Fidelity held natural gas and oil swap and collar derivative instruments and Cascade held natural gas swap derivative instruments. For more information on derivative instruments and commodity price risk, see Part II, Item 7A in the 2006 Annual Report, and Notes 12 and 15.

The following table summarizes derivative instruments entered into by Fidelity and Cascade as of September 30, 2007. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade to receive variable prices and pay fixed prices.

(Notional amount and fair value in thousands)

Fidelity	Weighted Average Fixed Price (Per MMBtu)	Forward Notional Volume (In MMBtu's)	Fair Value
Natural gas swap agreements maturing in 2007	$ 7.76	2,777	$ 6,393
Natural gas swap agreements maturing in 2008	$ 8.12	9,603	$ 7,737
Cascade Core			
Natural gas swap agreements maturing in 2007	$ 7.69	7,792	$ (13,421)
Natural gas swap agreements maturing in 2008	$ 7.72	20,104	$ (11,538)
Natural gas swap agreements maturing in 2009	$ 7.94	10,755	$ (4,479)
Natural gas swap agreements maturing in 2010	$ 7.73	4,576	$ (2,072)
Cascade Non-Core			
Natural gas swap agreements maturing in 2007	$ 6.58	601	$ (1,653)
Natural gas swap agreements maturing in 2008	$ 7.31	1,307	$ (686)

Fidelity	Weighted Average Floor/Ceiling Price (Per MMBtu)	Forward Notional Volume (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2007	$ 7.84/$10.13	3,508	$ 4,958
Natural gas collar agreements maturing in 2008	$ 7.27/$8.32	8,690	$ 2,428

Fidelity	Weighted Average Fixed Price (Per barrel)	Forward Notional Volume (In barrels)	Fair Value
Oil swap agreement maturing in 2007	$ 75.25	39	$ (249)

Fidelity	Weighted Average Floor/Ceiling Price (Per barrel)	Forward Notional Volume (In barrels)	Fair Value
Oil collar agreement maturing in 2008	$ 67.50/$78.70	73	$ (184)

Interest rate risk

There were no material changes to interest rate risk faced by the Company from those reported in the 2006 Annual Report. For more information on interest rate risk, see Part II, Item 7A in the 2006 Annual Report.

At September 30, 2007 and 2006, and December 31, 2006, the Company had no outstanding interest rate hedges.

Foreign currency risk

MDU Brasil's equity method investments in the Brazilian Transmission Lines are exposed to market risks from changes in foreign currency exchange rates between the U.S. dollar and the Brazilian Real. For further information on foreign currency risk, see Note 4 in the 2006 Annual Report.

At September 30, 2007 and 2006, and December 31, 2006, the Company had no outstanding foreign currency hedges.

ITEM 4. CONTROLS AND PROCEDURES

The following information includes the evaluation of disclosure controls and procedures by the Company's chief executive officer and the chief financial officer, along with any significant changes in internal controls of the Company.

Evaluation of disclosure controls and procedures
The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports it files under the Exchange Act is recorded, processed, summarized and reported within required time periods. The Company's chief executive officer and chief financial officer have evaluated the effectiveness of the Company's disclosure controls and procedures and they have concluded that, as of the end of the period covered by this report, such controls and procedures were effective.

Changes in internal controls
The Company maintains a system of internal accounting controls that is designed to provide reasonable assurance that the Company's transactions are properly authorized, the Company's assets are safeguarded against unauthorized or improper use, and the Company's transactions are properly recorded and reported to permit preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America. There were no changes in the Company's internal control over financial reporting that occurred during the period covered by this report that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see Note 20, which is incorporated by reference.

ITEM 1A. RISK FACTORS

This Form 10-Q contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions.

The Company is including the following factors and cautionary statements in this Form 10-Q to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Prospective Information. All these subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, also are expressly qualified by these factors and cautionary statements.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

There are no material changes in the Company's risk factors from those reported in Part I, Item 1A – Risk Factors of the 2006 Annual Report other than the completion of the Company's acquisition of Cascade and risks related to a reduction in construction activity at the construction materials and mining segment, as discussed below. These factors are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Economic volatility affects the Company's operations, as well as the demand for its products and services and, as a result, may have a negative impact on the Company's future revenues.

The global demand for natural resources, interest rates, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. A soft economy could negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, would negatively affect the demand for the Company's products and services.

The construction materials and mining segment is experiencing a reduction in construction activity and product sales volumes in some markets due to lower demand, which could negatively affect the Company's results of operations.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Between July 1, 2007 and September 30, 2007, the Company issued 450,139 shares of common stock, $1.00 par value, and the preference share purchase rights appurtenant thereto, as part of the consideration paid by the Company in the acquisition of businesses acquired by the Company in this period. The common stock and preference share purchase rights issued by the Company in these transactions were issued in a private transaction exempt from registration under the Securities Act of 1933, as amended, pursuant to Section 4 (2) thereof, Rule 506 promulgated thereunder, or both. The classes of persons to whom these securities were sold were either accredited investors or other persons to whom such securities were permitted to be offered under the applicable exemption.

ITEM 6. EXHIBITS

See the index to exhibits immediately preceding the exhibits filed with this report.

SIGNATURES

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

MDU RESOURCES GROUP, INC.

DATE: November 8, 2007	BY:	/s/ Vernon A. Raile Vernon A. Raile Executive Vice President, Treasurer and Chief Financial Officer
	BY:	/s/ Doran N. Schwartz Doran N. Schwartz Vice President and Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.

12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.