MDU RESOURCES GROUP INC
Form 10-Q
August 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 June 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 August 1, 2007: 182,112,362 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
CBNG	Coalbed natural gas
CEM	Colorado Energy Management, LLC, a direct wholly owned subsidiary of Centennial Resources
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 direct wholly owned subsidiary of Centennial Resources
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
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
Grynberg	Jack J. Grynberg
Hardin Generating Facility	116-MW coal-fired electric generating facility near Hardin, Montana
Hartwell	Hartwell Energy Limited Partnership
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
kW	Kilowatt
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
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
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
SEC	U.S. Securities and Exchange Commission
SEIS	Supplemental Environmental Impact Statement
SFAS	Statement of Financial Accounting Standards
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
SIP	State Implementation Plan
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
Wyoming Federal District Court	U.S. District Court for the District of Wyoming

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. These operations also supply related value-added products and services.

On July 2, 2007, the Company acquired Cascade. For further information, see Note 20.

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 16.

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PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$ 195,488	$ 170,589	$ 463,500	$ 461,640
Construction services, natural gas and oil production, construction materials and mining, and other	786,877	790,846	1,306,356	1,303,313
	982,365	961,435	1,769,856	1,764,953
Operating expenses:				
Fuel and purchased power	15,489	15,940	32,607	32,075
Purchased natural gas sold	40,294	39,361	139,129	166,321
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	46,659	42,816	91,315	80,102
Construction services, natural gas and oil production, construction materials and mining, independent power production and other	629,782	644,272	1,075,631	1,083,121
Depreciation, depletion and amortization	70,044	64,840	139,846	125,821
Taxes, other than income	37,312	31,976	69,574	64,216
	839,580	839,205	1,548,102	1,551,656
Operating income	142,785	122,230	221,754	213,297
Earnings from equity method investments	4,030	2,900	6,084	6,102
Other income	883	2,881	2,215	5,263
Interest expense	17,478	19,110	34,854	33,162
Income before income taxes	130,220	108,901	195,199	191,500
Income taxes	48,184	40,450	71,756	70,603
Income from continuing operations	82,036	68,451	123,443	120,897
	7,439	2,991	12,694	3,792

Income from discontinued operations, net of tax (Note 3)				
Net income	89,475	71,442	136,137	124,689
Dividends on preferred stocks	171	171	343	343
Earnings on common stock	$ 89,304	$ 71,271	$ 135,794	$ 124,346
Earnings per common share -- basic				
Earnings before discontinued operations	$ .45	$ .38	$ .68	$ .67
Discontinued operations, net of tax	.04	.02	.07	.02
Earnings per common share -- basic	$ .49	$ .40	$ .75	$ .69
Earnings per common share -- diluted				
Earnings before discontinued operations	$ .45	$ .38	$ .67	$ .67
Discontinued operations, net of tax	.04	.01	.07	.02
Earnings per common share -- diluted	$ .49	$ .39	$ .74	$ .69
Dividends per common share	$ .1350	$ .1267	$ .2700	$ .2534
Weighted average common shares outstanding -- basic	181,847	179,911	181,595	179,867
Weighted average common shares outstanding -- diluted	182,746	181,107	182,469	181,050

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

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

	June 30, 2007	June 30, 2006	December 31, 2006
	(In thousands, except shares and per share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 68,134	$ 114,787	$ 73,078
Receivables, net	642,559	643,439	622,478
Inventories	221,179	206,682	204,440
Deferred income taxes	---	11,637	---
Prepayments and other current assets	95,235	90,898	81,083
Current assets held for sale and related to discontinued operations	69,662	13,033	12,656
	1,096,769	1,080,476	993,735
Investments	136,585	106,226	155,111
Property, plant and equipment	4,953,171	4,502,534	4,727,725
Less accumulated depreciation, depletion and amortization	1,851,825	1,627,887	1,735,302
	3,101,346	2,874,647	2,992,423
Deferred charges and other assets:			
Goodwill	227,029	227,483	224,298
Other intangible assets, net	17,150	17,787	22,802
Other	113,193	100,785	103,840
Noncurrent assets held for sale and related to discontinued operations	410,662	422,025	411,265
	768,034	768,080	762,205
	$ 5,102,734	$ 4,829,429	$ 4,903,474
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Long-term debt due within one year	$ 131,661	$ 159,168	$ 84,034
Accounts payable	284,208	290,166	289,836
Taxes payable	38,769	31,248	54,290
Deferred income taxes	1,396	---	5,969
Dividends payable	24,725	22,967	24,606
Other accrued liabilities	155,890	154,908	180,327
Current liabilities held for sale and related to discontinued operations	14,156	7,986	14,900
	650,805	666,443	653,962
Long-term debt	1,224,286	1,299,175	1,170,548
Deferred credits and other liabilities:			
Deferred income taxes	570,590	543,278	546,602
Other liabilities	349,895	279,617	336,916
Noncurrent liabilities held for sale and related to discontinued operations	35,488	30,466	30,533
	955,973	853,361	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, 182,416,029 at June 30, 2007, 180,515,943 at June 30, 2006 and 181,557,543 at December 31, 2006	182,416	180,516	181,558
Other paid-in capital	895,838	856,366	874,253
Retained earnings	1,190,935	963,194	1,104,210
Accumulated other comprehensive loss	(8,893)	(1,000)	(6,482)
Treasury stock at cost - 538,921 shares at June 30, 2007, June 30, 2006 and December 31, 2006	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,256,670	1,995,450	2,149,913
Total stockholders' equity	2,271,670	2,010,450	2,164,913
	$ 5,102,734	$ 4,829,429	$ 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)

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(In thousands)	
Operating activities:		
Net income	$ 136,137	$ 124,689
Income from discontinued operations, net of tax	12,694	3,792
Income from continuing operations	123,443	120,897
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	139,846	125,821
Earnings, net of distributions, from equity method investments	(722)	(3,107)
Deferred income taxes	24,756	15,942
Changes in current assets and liabilities, net of acquisitions:		
Receivables	(14,083)	(31,563)
Inventories	(16,690)	(33,173)
Other current assets	(25,259)	(37,513)
Accounts payable	(11,644)	29,003
Other current liabilities	(38,040)	(10,866)
Other noncurrent changes	(1,107)	5,792
Net cash provided by continuing operations	180,500	181,233
Net cash provided by (used in) discontinued operations	(41,884)	10,234
Net cash provided by operating activities	138,616	191,467
Investing activities:		
Capital expenditures	(242,729)	(240,606)
Acquisitions, net of cash acquired	(329)	(109,250)
Net proceeds from sale or disposition of property	10,848	14,878
Investments	17,309	(5,184)
Net cash used in continuing operations	(214,901)	(340,162)
Net cash used in discontinued operations	(1,379)	(38,119)
Net cash used in investing activities	(216,280)	(378,281)
Financing activities:		
Issuance of long-term debt	186,578	335,653
Repayment of long-term debt	(85,028)	(97,158)
Proceeds from issuance of common stock	15,775	2,709
Dividends paid	(49,300)	(45,914)
Tax benefit on stock-based compensation	4,505	3,167
Net cash provided by continuing operations	72,530	198,457
Net cash provided by discontinued operations	---	---
Net cash provided by financing activities	72,530	198,457
Effect of exchange rate changes on cash and cash equivalents	190	(2,354)
Increase (decrease) in cash and cash equivalents	(4,944)	9,289
Cash and cash equivalents -- beginning of year	73,078	105,498
Cash and cash equivalents -- end of period	$ 68,134	$ 114,787

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

June 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. **Discontinued operations**

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. Innovatum, a component of the pipeline and energy services segment, specialized in cable and pipeline magnetization and location. 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 within one year of the initial plan to sell. 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 will 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 all of the domestic independent power production assets, including CEM, are presented as discontinued operations. For more information on the sale of the domestic independent power production assets, see Note 20.

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 loss 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 June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
		(In thousands)		
Operating revenues	$ 439	$ 632	$ 689	$ 1,142
Income (loss) from discontinued operations before income tax expense (benefit)	104	(389)	28	(862)
Income tax expense (benefit)	15	(116)	(29)	(265)
Income (loss) from discontinued operations, net of tax	$ 89	$ (273)	$ 57	$ (597)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
		(In thousands)		
Operating revenues	$ 64,291	$ 11,716	$ 98,887	$ 22,982
Income from discontinued operations before income tax expense (benefit)	9,532	2,540	16,923	3,031
Income tax expense (benefit)	2,182	(724)	4,286	(1,358)
Income from discontinued operations, net of tax	$ 7,350	$ 3,264	$ 12,637	$ 4,389

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:

	June 30, 2007	June 30, 2006	December 31, 2006
		(In thousands)	
Cash and cash equivalents	$ 1,575	$ 1,911	$ 1,878
Receivables, net	7,878	7,753	8,307
Inventories	555	1,064	490
Prepayments and other current assets	59,654	2,305	1,981
Total current assets held for sale and related to	$ 69,662	$ 13,033	$ 12,656

discontinued operations						
Net property, plant and equipment	$	391,708	$	396,434	$	390,679
Goodwill		11,167		15,472		11,167
Other intangible assets, net		7,241		7,763		7,162
Other		546		2,356		2,257
Total noncurrent assets held for sale and related to discontinued operations	$	410,662	$	422,025	$	411,265
Accounts payable	$	7,264	$	4,785	$	11,557
Other accrued liabilities		6,892		3,201		3,343
Total current liabilities held for sale and related to discontinued operations	$	14,156	$	7,986	$	14,900
Deferred income taxes	$	32,888	$	28,149	$	27,956
Other liabilities		2,600		2,317		2,577
Total noncurrent liabilities held for sale and related to discontinued operations	$	35,488	$	30,466	$	30,533

4. **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.

5. **Allowance for doubtful accounts**

The Company's allowance for doubtful accounts as of June 30, 2007 and 2006, and December 31, 2006, was $7.7 million, $7.2 million and $7.7 million, respectively.

6. **Natural gas in underground storage**

Natural gas in underground storage for the Company's regulated operations is 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 $9.7 million, $19.4 million and $32.6 million at June 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 June 30, 2007 and 2006, and December 31, 2006, respectively.

7. **Inventories**

Inventories, other than natural gas in underground storage for the Company’s regulated operations, consisted primarily of aggregates held for resale of $100.6 million, $93.1 million and $88.1 million; materials and supplies of $75.0 million, $70.3 million and $54.1 million; and other inventories of $35.9 million, $23.9 million and $29.6 million, as of June 30, 2007 and 2006, and December 31, 2006, respectively. These inventories were stated at the lower of average cost or market value.

8. **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 six months ended June 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.

9. **Cash flow information**

Cash expenditures for interest and income taxes were as follows:

	Six Months Ended June 30,	
	2007	2006
	(In thousands)	
Interest, net of amount capitalized	$ 35,028	$27,988
Income taxes	$113,919	$78,382

Income taxes paid for the six months ended June 30, 2007, increased from the amount paid for the six months ended June 30, 2006, primarily due to estimated quarterly income tax payments on the estimated gain on the sale of the domestic independent power production assets as discussed in Note 20.

10. **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 15.

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.

11. **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 14.

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

	Three Months Ended June 30,	
	2007	2006
	(In thousands)	
Net income	$ 89,475	$71,442
Other comprehensive income:		
Net unrealized gain on derivative instruments qualifying as hedges:		

Net unrealized gain on derivative instruments arising during the period, net of tax of $6,096 and $4,051 in 2007 and 2006, respectively	9,739	6,471
Less: Reclassification adjustment for gain on derivative instruments included in net income, net of tax of $1,509 and $1,033 in 2007 and 2006, respectively	2,411	1,650
Net unrealized gain on derivative instruments qualifying as hedges	7,328	4,821
Foreign currency translation adjustment	3,576	(2,176)
	10,904	2,645
Comprehensive income	$ 100,379	$74,087

	Six Months Ended June 30,	
	2007	2006
	(In thousands)	
Net income	$ 136,137	$ 124,689
Other comprehensive income (loss):		
Net unrealized gain (loss) on derivative instruments qualifying as hedges:		
Net unrealized gain on derivative instruments arising during the period, net of tax of $1,204 and $17,652 in 2007 and 2006, respectively	1,923	28,197
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $6,272 and $4,254 in 2007 and 2006, respectively	10,018	(6,796)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(8,095)	34,993
Foreign currency translation adjustment	5,684	(2,177)
	(2,411)	32,816
Comprehensive income	$ 133,726	$ 157,505

12. **Equity method investments**

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

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. For more information, see Note 20.

In August 2006, MDU Brasil acquired ownership interests in companies owning three electric 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.

At June 30, 2007 and 2006, and December 31, 2006, the Company's equity method investments had total assets of $469.2 million, $228.9 million and $583.6 million, respectively, and long-term debt of $277.2 million, $149.5 million and $321.5 million, respectively. The Company's investment in its equity method investments was approximately $80.6 million, $50.1 million and $102.0 million, including undistributed earnings of $7.6 million, $6.5 million and $8.5 million, at June 30, 2007 and 2006, and December 31, 2006, respectively.

13. **Goodwill and other intangible assets**

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

Six Months Ended June 30, 2007	Balance as of January 1, 2007	Goodwill Acquired During the Year*	Balance as of June 30, 2007
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	86,942	3,596	90,538
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and mining	136,197	(865)	135,332
Independent power production	---	---	---
Other	---	---	---
Total	$ 224,298	$ 2,731	$ 227,029

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

Six Months Ended June 30, 2006	Balance as of January 1, 2006	Goodwill Acquired During the Year*	Balance as of June 30, 2006
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	80,970	5,981	86,951
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and mining	133,264	6,109	139,373
Independent power production	---	---	---
Other	---	---	---
Total	$ 215,393	$ 12,090	$ 227,483

* 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*	Balance as of December 31, 2006
		(In thousands)	
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:

	June 30, 2007	June 30, 2006	December 31, 2006
	(In thousands)		
Amortizable intangible assets:			
Customer relationships	$ 13,959	$ 6,900	$ 13,030
Accumulated amortization	(3,234)	(855)	(1,890)
	10,725	6,045	11,140
Noncompete agreements	7,434	11,984	12,886
Accumulated amortization	(2,926)	(8,900)	(8,540)
	4,508	3,084	4,346
Acquired contracts	1,186	8,164	8,307
Accumulated amortization	(1,156)	(3,802)	(4,646)
	30	4,362	3,661
Other	2,559	4,662	5,062
Accumulated amortization	(672)	(890)	(1,407)
	1,887	3,772	3,655
Unamortizable intangible assets	---	524	---
Total	$ 17,150	$ 17,787	$ 22,802

The unamortizable intangible assets at June 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 six months ended June 30, 2007, was $900,000 and $1.9 million, respectively. Amortization expense for the three and six months ended June 30, 2006, and for the year ended December 31, 2006, was $1.3 million, $2.1 million and $4.3 million, respectively. Estimated amortization expense for amortizable intangible assets is $3.7 million in 2007, $2.8 million in 2008, $2.4 million in 2009, $1.9 million in 2010, $1.5 million in 2011 and $6.8 million thereafter.

14. **Derivative instruments**

From time to time, the Company utilizes 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. As of June 30, 2007, the Company had no outstanding foreign currency or interest rate hedges. The following information should be read in conjunction with Notes 1 and 7 in the Company's Notes to Consolidated Financial Statements in the 2006 Annual Report.

At June 30, 2007, Fidelity held natural gas swap and collar derivative instruments designated as cash flow hedging instruments and had no outstanding oil derivative instruments.

Hedging activities

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. Each of the price swap and collar agreements was designated as a hedge of the forecasted sale of the related production.

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 production 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 the Company receives for its natural gas and oil production are also generally based on market prices.

For the three and six months ended June 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 amount of ineffectiveness for the three and six months ended June 30, 2006, related to these collar agreements was approximately $979,000 (before tax) and was recorded in operation and maintenance expense. The amount of hedge ineffectiveness on Fidelity’s remaining hedges was immaterial for the three and six months ended June 30, 2006. For the three and six months ended June 30, 2007 and 2006, Fidelity did not exclude any components of the derivative instruments’ gain or loss 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 June 30, 2007, the maximum term of Fidelity’s swap and collar agreements, in which Fidelity is hedging its exposure to the variability in future cash flows for forecasted transactions, is 18 months. The Company estimates that over the next 12 months net gains of approximately $11.6 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.

15. **Uncertainty in income taxes**

On January 1, 2007, the Company adopted FIN 48 as discussed in Note 10.

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.

16. **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 western Minnesota. These operations also supply related value-added products and services.

The construction services segment specializes in electric line construction, pipeline construction, 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 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. This segment's domestic operations owned, built and operated electric generating facilities in the United States and had investments in natural resource-based projects. Electric capacity and energy produced at its power plants primarily were sold under mid- and long-term contracts to nonaffiliated entities. For more information regarding the discontinued operations of the domestic operations of this segment and the sale of these assets, see Notes 3 and 20.

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 June 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 44,591	$ ---	$ 3,568
Natural gas distribution	53,403	---	(559)
Pipeline and energy services	97,494	14,660	6,228
	195,488	14,660	9,237

Construction services	263,483	349	13,026
Natural gas and oil production	67,924	59,471	35,166
Construction materials and mining	455,470	---	25,541
Independent power production	---	---	5,971
Other	---	2,440	363
	786,877	62,260	80,067
Intersegment eliminations	---	(76,920)	---
Total	$ 982,365	$ ---	$ 89,304

Three Months Ended June 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 40,875	$ ---	$ 509
Natural gas distribution	45,845	---	(2,530)
Pipeline and energy services	83,869	18,568	5,580
	170,589	18,568	3,559
Construction services	243,062	136	9,679
Natural gas and oil production	62,906	51,206	30,979
Construction materials and mining	484,878	---	25,311
Independent power production	---	---	1,504
Other	---	2,318	239
	790,846	53,660	67,712
Intersegment eliminations	---	(72,228)	---
Total	$ 961,435	$ ---	$ 71,271

Six Months Ended June 30, 2007	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 91,695	$ ---	$ 7,353
Natural gas distribution	189,465	---	5,584
Pipeline and energy services	182,340	42,952	11,938
	463,500	42,952	24,875
Construction services	500,120	474	20,260
Natural gas and oil production	123,193	122,781	65,787
Construction materials and mining	683,043	---	15,745
Independent power production	---	---	8,488
Other	---	4,880	639
	1,306,356	128,135	110,919
Intersegment eliminations	---	(171,087)	---
Total	$ 1,769,856	$ ---	$ 135,794

Six Months Ended June 30, 2006	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 85,905	$ ---	$ 4,305

Natural gas distribution	198,124	---	2,793
Pipeline and energy services	177,611	51,374	10,149
	461,640	51,374	17,247
Construction services	466,747	246	15,077
Natural gas and oil production	118,004	124,498	72,237
Construction materials and mining	718,562	---	16,437
Independent power production	---	---	2,846
Other	---	4,087	502
	1,303,313	128,831	107,099
Intersegment eliminations	---	(180,205)	---
Total	$ 1,764,953	$ ---	$ 124,346

The pipeline and energy services segment recognized income from discontinued operations, net of tax, of $89,000 and $57,000 for the three and six months ended June 30, 2007, respectively, and a loss from discontinued operations, net of tax of $273,000 and $597,000 for the three and six months ended June 30, 2006, respectively. The independent power production segment recognized income from discontinued operations, net of tax, of $7.4 million and $12.6 million for the three and six months ended June 30, 2007, respectively, and $3.3 million and $4.4 million for the three and six months ended June 30, 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.

17. **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 June 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	$ 2,011	$ 2,301	$ 447	$ 472
Interest cost	4,222	4,074	1,180	928
Expected return on assets	(5,094)	(4,718)	(1,279)	(926)
Amortization of prior service cost	207	257	14	12
Recognized net actuarial (gain) loss	426	509	164	(85)
Amortization of net transition obligation (asset)	---	(1)	635	531
Net periodic benefit cost, including amount capitalized	1,772	2,422	1,161	932
Less amount capitalized	217	225	90	79
Net periodic benefit cost	$ 1,555	$ 2,197	$ 1,071	$ 853

Six Months Ended June 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	$ 4,261	$ 4,602	$ 980	$ 943
Interest cost	8,363	8,148	2,118	1,857
Expected return on assets	(10,164)	(9,436)	(2,372)	(1,851)
Amortization of prior service cost	416	513	25	23
Recognized net actuarial (gain) loss	500	1,018	(149)	(169)
Amortization of net transition obligation (asset)	---	(2)	1,166	1,062
Net periodic benefit cost, including amount capitalized	3,376	4,843	1,768	1,865
Less amount capitalized	368	381	141	125
Net periodic benefit cost	$ 3,008	$ 4,462	$ 1,627	$ 1,740

In addition to the qualified plan defined pension benefits reflected in the table, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that generally provides for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company's net periodic benefit cost for this plan for the three and six months ended June 30, 2007, was $2.1 million and $3.9 million, respectively. The Company's net periodic benefit cost for this plan for the three and six months ended June 30, 2006, was $1.9 million and $3.9 million, respectively.

18. **Regulatory matters and revenues subject to refund**

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 for approval of advance determination of prudence of Montana-Dakota's participation and ownership interest in Big Stone II, which is expected to be completed in 2012. Hearings on the application were held June 26-28, 2007. An order on the application is expected by September 2007.

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.

19. **Contingencies**

Litigation

Royalties Case In June 1997, Grynberg, acting on behalf of the United States, filed suit under the Federal False Claims Act against Williston Basin and Montana-Dakota. He also filed more than 70 similar suits against natural gas transmission companies and producers, gatherers and processors of natural gas. Grynberg alleged improper measurement of the heating content and volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. All cases were consolidated in Wyoming Federal District Court.

In October 2006, the Wyoming Federal District Court ordered that the actions against Williston Basin and Montana-Dakota be dismissed. Grynberg filed a Notice of Appeal of the decision to the U.S. Tenth Circuit Court of Appeals in November 2006.

On March 6, 2007, a settlement was reached between Grynberg, Williston Basin and Montana-Dakota. The case was dismissed by the U.S. Tenth Circuit Court of Appeals on April 20, 2007.

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 Powder River Basin in Montana 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 has been fully briefed and argued before the Ninth Circuit and the parties are awaiting a decision of the court. 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 development 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 February 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 that 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 ignoring the BER's recently adopted amendment to the non-degradation policy. 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.

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 will continue to vigorously defend its interests in all CBNG-related lawsuits and related actions in which it is involved, including the Ninth Circuit injunction and 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.

Montana-Dakota expects the EPA to initiate a rulemaking proceeding to formally approve the conclusions contained in the September 2005 ND Health Department decision and the August 2005 final report. Once concluded, this rulemaking should result in a revision to the North Dakota SIP that, in turn, should allow for the dismissal of the case in Burleigh County District Court referenced above.

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 prevention of significant deterioration 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 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 June 30, 2007, Williston Basin estimated approximately 9 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 are currently briefing the issues.

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.

As noted above, Williston Basin estimates that as of June 30, 2007, Howell and Anadarko had diverted approximately 9 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.

In light of the actions of Howell and Anadarko, Williston Basin installed additional compression at the site in order to maintain deliverability into the transmission system. While installation of the additional compression has provided 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. 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 this proceeding.

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 also agreed to obtain an amended air permit for the Hardin Generating Facility, the application process for which Centennial Resources initiated during the sales process, and to pay certain fines and penalties, if any, assessed against the facility on or prior to the date that the facility complies with the amended air permit, as well as certain costs related to obtaining the amended air permit. The Hardin Generating Facility has received three notices of violation from the Montana DEQ relating to emissions exceedances associated with startup and maintenance periods for the Hardin Generating Facility. The Company is working with the Montana DEQ to address these issues and to secure the amended air permit and is unable to estimate what, if any, fines may be imposed by the Montana DEQ.

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 20, 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.

In addition, WBI Holdings has guaranteed certain of Fidelity’s natural gas price swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas price swap and collar agreements, as the amount of the obligation is dependent upon natural gas commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas price swap and collar agreements at June 30, 2007, expire in 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 $900,000 and was reflected on the Consolidated Balance Sheets at June 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, electric power supply agreements, gathering contracts, a conditional purchase agreement and certain other guarantees. At June 30, 2007, the fixed maximum amounts guaranteed under these agreements aggregated $543.2 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $7.0 million in 2007; $87.0 million in 2008; $366.6 million in 2009; $30.4 million in 2010; $23.0 million in 2011; $12.7 million in 2012; $11.2 million in 2017; $300,000 in 2028; $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. A guarantee for an unfixed amount estimated at $250,000 at June 30, 2007, has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $674,000 and was reflected on the Consolidated Balance Sheet at June 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.

Centennial has outstanding letters of credit to third parties related to insurance policies and other agreements that guarantee the performance of other subsidiaries of the Company. At June 30, 2007, the fixed maximum amounts guaranteed under these letters of credit aggregated $42.6 million. In 2007 and 2008, $9.6 million and $33.0 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at June 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 June 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 $1.6 million, which was not reflected on the Consolidated Balance Sheet at June 30, 2007, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial and Knife River have issued guarantees to third parties related to routine purchases by their subsidiaries 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 in relation 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 June 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 June 30, 2007, approximately $535 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

20. **<u>Subsequent events</u>**

On July 2, 2007, the acquisition of Cascade was finalized and Cascade became an indirect wholly owned subsidiary of the Company. The total value of the transaction, including the outstanding indebtedness of Cascade, is approximately $475 million. Cascade's natural gas service areas are concentrated in western and south central Washington and south central and eastern Oregon. Future results of Cascade will be part of the Company's natural gas distribution segment.

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, the Company paid down $220 million of the outstanding principal balance. This term loan agreement matures on June 27, 2008.

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 is valued at $636 million, which includes the assumption of approximately $36 million of project-related debt. The estimated gain on the sale of the assets is expected to be approximately $90 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.

<u>ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS</u>

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, credit 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; recruiting, developing and retaining 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. Some of our markets are affected by the slowdown in housing, which should be partially mitigated by increased commercial spending.

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 June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006

	(Dollars in millions, where applicable)			
Electric	$ 3.6	$ .5	$ 7.4	$ 4.3
Natural gas distribution	(.6)	(2.5)	5.6	2.8
Construction services	13.0	9.7	20.3	15.1
Pipeline and energy services	6.1	5.9	11.8	10.8
Natural gas and oil production	35.2	31.0	65.8	72.2
Construction materials and mining	25.5	25.3	15.7	16.4
Independent power production	(1.4)	(1.8)	(4.1)	(1.6)
Other	.4	.2	.6	.5
Earnings before discontinued operations	81.8	68.3	123.1	120.5
Income from discontinued operations, net of tax	7.5	3.0	12.7	3.8
Earnings on common stock	$ 89.3	$ 71.3	$ 135.8	$ 124.3
Earnings per common share - basic:				
Earnings before discontinued operations	$ .45	$ .38	$ .68	$ .67
Discontinued operations, net of tax	.04	.02	.07	.02
Earnings per common share - basic	$ .49	$ .40	$ .75	$ .69
Earnings per common share - diluted:				
Earnings before discontinued operations	$ .45	$ .38	$ .67	$ .67
Discontinued operations, net of tax	.04	.01	.07	.02
Earnings per common share - diluted	$ .49	$ .39	$ .74	$ .69
Return on average common equity for the 12 months ended			15.2%	15.1%

Three Months Ended June 30, 2007 and 2006 Consolidated earnings for the quarter ended June 30, 2007, increased $18.0 million from the comparable prior period largely due to:

- Increased combined natural gas and oil production of 4 percent, partially offset by higher depreciation, depletion and amortization expense at the natural gas and oil production business
- Increased income from discontinued operations, net of tax, largely the absence in 2007 of depreciation expense related to assets held for sale and earnings related to an electric generating facility construction project at the independent power production business
- Higher earnings from increased retail sales volumes and margins and decreased operation and maintenance expense at the electric business
- Higher earnings from increased construction margins and equipment sales and rentals at the construction services business

Six Months Ended June 30, 2007 and 2006 Consolidated earnings for the six months ended June 30, 2007, increased $11.5 million from the comparable prior period largely due to:

- Increased income from discontinued operations, net of tax, largely the absence in 2007 of depreciation expense related to assets held for sale, earnings related to an electric generating facility construction project and higher earnings from the Hardin Generating Station at the independent power production business
- Higher earnings from construction services business, as previously discussed
- Higher earnings from increased retail sales volumes and margins at the electric business

Partially offsetting this increase were lower earnings at the natural gas and oil production business.

FINANCIAL AND OPERATING DATA

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

Electric

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(Dollars in millions, where applicable)			
Operating revenues	$ 44.6	$ 40.9	$ 91.7	$ 85.9
Operating expenses:				
Fuel and purchased power	15.5	16.0	32.6	32.0
Operation and maintenance	14.5	15.7	29.5	29.7
Depreciation, depletion and amortization	5.6	5.3	11.2	10.6
Taxes, other than income	2.1	2.0	4.3	4.3
	37.7	39.0	77.6	76.6
Operating income	6.9	1.9	14.1	9.3
Earnings	$ 3.6	$ .5	$ 7.4	$ 4.3
Retail sales (million kWh)	596.3	563.0	1,242.0	1,175.9
Sales for resale (million kWh)	47.0	85.3	91.2	251.7
Average cost of fuel and purchased power per kWh	$ .024	$ .024	$ .024	$ .022

Three Months Ended June 30, 2007 and 2006 Electric earnings increased $3.1 million due to:

- Higher retail sales volumes and margins
- Decreased operation and maintenance expense of $800,000 (after tax), largely due to lower maintenance expense at certain electric generating stations

Partially offsetting this increase were lower sales for resale volumes.

Six Months Ended June 30, 2007 and 2006 Electric earnings increased $3.1 million largely due to higher retail sales volumes and margins and higher sales for resale margins, partially offset by lower sales for resale volumes.

Natural Gas Distribution

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(Dollars in millions, where applicable)			
Operating revenues	$ 53.4	$ 45.8	$ 189.5	$ 198.1
Operating expenses:				
Purchased natural gas sold	34.3	33.4	140.5	161.8
Operation and maintenance	15.6	13.0	31.2	24.8
Depreciation, depletion and amortization	2.5	2.4	5.0	4.8
Taxes, other than income	1.5	1.5	3.2	3.0
	53.9	50.3	179.9	194.4
Operating income (loss)	(.5)	(4.5)	9.6	3.7
Earnings (loss)	$ (.6)	$ (2.5)	$ 5.6	$ 2.8
Volumes (MMdk):				
Sales	5.3	4.6	21.2	18.8

Transportation	2.9	2.8	6.3	7.2
Total throughput	8.2	7.4	27.5	26.0
Degree days (% of normal)*	94%	68%	94%	82%
Average cost of natural gas, including transportation, per dk	$ 6.44	$ 7.29	$ 6.64	$ 8.59

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

Three Months Ended June 30, 2007 and 2006 The natural gas distribution business experienced a seasonal loss of $600,000 in the second quarter of 2007 compared to a loss of $2.5 million in the second quarter of 2006. The increase in earnings of $1.9 million was largely due to:

· Decreased payroll and benefit-related costs of $1.0 million (after tax), including the absence in 2007 of the 2006 early retirement program costs

· Increased retail sales volumes, resulting from 39 percent colder weather than last year

· Higher nonregulated energy-related services contributed to the earnings increase as well as to the increase in revenues and operation and maintenance expense

Six Months Ended June 30, 2007 and 2006 Earnings at the natural gas distribution business increased $2.8 million due to:

· Decreased payroll and benefit-related costs of $1.1 million (after tax), including the absence in 2007 of the 2006 early retirement program costs

· Increased retail sales volumes, resulting from 14 percent colder weather than last year

· Higher nonregulated energy-related services

The pass-through of lower natural gas prices is reflected in the decrease in both revenues and purchased natural gas sold. The decrease in revenues was partially offset by revenues from nonregulated energy-related services. Nonregulated energy-related services also contributed to the operation and maintenance expense increase.

Construction Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
		(In millions)		
Operating revenues	$ 263.8	$ 243.2	$ 500.6	$ 467.0
Operating expenses:				
Operation and maintenance	230.6	216.5	442.4	419.3
Depreciation, depletion and amortization	3.4	3.9	6.9	7.4
Taxes, other than income	7.5	5.5	16.2	12.9
	241.5	225.9	465.5	439.6
Operating income	22.3	17.3	35.1	27.4
Earnings	$ 13.0	$ 9.7	$ 20.3	$ 15.1

Three Months Ended June 30, 2007 and 2006 Construction services earnings increased $3.3 million due to:

· Higher construction margins of $2.7 million (after tax), including industrial-related work

· Increased equipment sales and rentals

Six Months Ended June 30, 2007 and 2006 Construction services earnings increased $5.2 million due to:

- Higher construction margins of $4.4 million (after tax) in all regions, including industrial-related work
- Increased equipment sales and rentals

Pipeline and Energy Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(Dollars in millions)			
Operating revenues:				
Pipeline	$ 28.6	$ 26.1	$ 54.5	$ 46.8
Energy services	83.6	76.4	170.8	182.2
	112.2	102.5	225.3	229.0
Operating expenses:				
Purchased natural gas sold	75.8	69.3	155.4	167.1
Operation and maintenance	16.6	14.1	30.6	25.7
Depreciation, depletion and amortization	5.2	5.1	10.6	10.0
Taxes, other than income	2.7	2.6	5.5	5.1
	100.3	91.1	202.1	207.9
Operating income	11.9	11.4	23.2	21.1
Income from continuing operations	6.1	5.9	11.8	10.8
Income (loss) from discontinued operations, net of tax	.1	(.3)	.1	(.6)
Earnings	$ 6.2	$ 5.6	$ 11.9	$ 10.2
Transportation volumes (MMdk):				
Montana-Dakota	7.1	7.1	15.1	15.1
Other	29.7	28.0	50.2	46.2
	36.8	35.1	65.3	61.3
Gathering volumes (MMdk)	22.5	21.2	44.7	42.9

Three Months Ended June 30, 2007 and 2006 Pipeline and energy services experienced an increase in earnings of $600,000 due to:

- Higher transportation and gathering volumes of $900,000 (after tax)
- Higher gathering rates of $400,000 (after tax)
- Higher storage services revenue of $300,000 (after tax)

Partially offsetting these increases were higher operation and maintenance expenses, including payroll and material costs.

Six Months Ended June 30, 2007 and 2006 Pipeline and energy services experienced an increase in earnings of $1.7 million due to:

- Higher storage services revenue of $2.2 million (after tax)
- Higher transportation and gathering volumes of $1.9 million (after tax)
- Higher gathering rates of $800,000 (after tax)

Partially offsetting these increases were higher operation and maintenance expenses, primarily related to the natural gas storage litigation and higher payroll and material costs. For more information regarding natural gas storage litigation, see Note 19.

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

Natural Gas and Oil Production

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(Dollars in millions, where applicable)			
Operating revenues:				
Natural gas	$ 96.1	$ 87.2	$ 190.0	$ 192.5
Oil	31.2	25.4	55.8	46.5
Other	.1	1.5	.2	3.5
	127.4	114.1	246.0	242.5
Operating expenses:				
Purchased natural gas sold	---	1.7	.3	3.7
Operation and maintenance:				
Lease operating costs	15.6	12.3	31.1	24.2
Gathering and transportation	5.0	4.7	9.5	9.4
Other	9.1	9.4	17.5	16.8
Depreciation, depletion and amortization	29.8	25.8	59.6	50.3
Taxes, other than income:				
Production and property taxes	9.3	8.0	18.2	18.0
Other	.3	.4	.5	.5
	69.1	62.3	136.7	122.9
Operating income	58.3	51.8	109.3	119.6
Earnings	$ 35.2	$ 31.0	$ 65.8	$ 72.2
Production:				
Natural gas (MMcf)	15,231	15,242	30,671	30,604
Oil (MBbls)	589	471	1,145	921
Average realized prices (including hedges):				
Natural gas (per Mcf)	$ 6.31	$ 5.72	$ 6.20	$ 6.29
Oil (per barrel)	$ 52.83	$ 54.00	$ 48.71	$ 50.43
Average realized prices (excluding hedges):				
Natural gas (per Mcf)	$ 5.82	$ 5.15	$ 5.78	$ 6.03
Oil (per barrel)	$ 52.83	$ 55.71	$ 48.71	$ 51.77
Production costs, including taxes, per net equivalent Mcf:				
Lease operating costs	$ .83	$ .68	$ .83	$ .67
Gathering and transportation	.27	.26	.25	.26
Production and property taxes	.50	.45	.49	.50
	$ 1.60	$ 1.39	$ 1.57	$ 1.43

Three Months Ended June 30, 2007 and 2006 The natural gas and oil production business experienced a $4.2 million increase in earnings due to:

- Higher average realized gas prices of 10 percent
- Increased combined natural gas and oil production of 4 percent, largely due to increased production at the South Texas properties, as well as from the May 2006 Big Horn acquisition

Partially offsetting these increases were:

- Higher depreciation, depletion and amortization expense of $2.5 million (after tax) due to higher depletion rates and increased production
- Higher lease operating expense of $2.2 million (after tax), largely CBNG and acquisition- related costs
- Lower average realized oil prices of 2 percent

Six Months Ended June 30, 2007 and 2006 The natural gas and oil production business experienced a $6.4 million decrease in earnings due to:

- Higher depreciation, depletion and amortization expense of $5.7 million (after tax), as previously discussed
- Higher lease operating expense of $4.3 million (after tax), as previously discussed
- Lower average realized gas prices of 1 percent and lower average realized oil prices of 3 percent
- Increased general and administrative expense of $1.0 million (after tax), primarily due to higher payroll-related costs

Partially offsetting these decreases were increased combined natural gas and oil production of 4 percent, largely due to increased production resulting from the May 2006 Big Horn acquisition, as well as from the South Texas properties.

Construction Materials and Mining

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(Dollars in millions)			
Operating revenues	$ 455.5	$ 484.9	$ 683.0	$ 718.6
Operating expenses:				
Operation and maintenance	372.8	404.5	581.6	620.2
Depreciation, depletion and amortization	23.2	22.1	45.8	42.2
Taxes, other than income	13.9	11.9	21.6	20.3
	409.9	438.5	649.0	682.7
Operating income	45.6	46.4	34.0	35.9
Earnings	$ 25.5	$ 25.3	$ 15.7	$ 16.4
Sales (000's):				
Aggregates (tons)	10,339	13,341	15,896	19,425
Asphalt (tons)	1,769	2,356	2,105	2,689
Ready-mixed concrete (cubic yards)	1,092	1,260	1,718	1,971

Three Months Ended June 30, 2007 and 2006 Earnings at the construction materials and mining business increased $200,000 due to:

- Higher earnings of $1.7 million (after tax) from asphalt operations, largely due to higher realized prices, partially offset by lower volumes
- Increased earnings realized from this segment's liquid asphalt materials business of $1.6 million (after tax), largely due to higher realized oil prices
- Earnings from companies acquired since the comparable prior period which contributed 4 percent to earnings

Partially offsetting these increases were:

- Lower earnings of $2.1 million (after tax) from aggregate and ready-mixed concrete operations, largely due to lower volumes, partially offset by higher realized prices

· Higher depreciation, depletion and amortization of $500,000 (after tax), primarily due to higher plant and equipment balances

Lower product sales volumes reflect the slow down in the residential housing market.

Six Months Ended June 30, 2007 and 2006 Earnings at the construction materials and mining business decreased $700,000 due to:

· Lower earnings of $2.6 million (after tax) from ready-mixed concrete operations, due to lower margins and volumes
· Lower earnings of $1.3 million (after tax) from aggregate operations, largely due to lower volumes, partially offset by higher realized prices
· Higher depreciation, depletion and amortization of $1.8 million (after tax), as previously discussed

Partially offsetting these decreases were:

· Higher earnings from construction, largely due to strong demand in the Northwest region
· Increased earnings from asphalt operations of $1.9 million (after tax), largely due to higher prices, partially offset by lower volumes
· Increased earnings realized from this segment’s liquid asphalt materials business of $1.6 million (after tax), largely due to higher realized oil prices

Lower product sales volumes reflect the slow down in the residential housing market.

Independent Power Production

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(Dollars in millions)			
Operating revenues	$ ---	$ ---	$ ---	$ ---
Operating expenses:				
Operation and maintenance	1.9	2.3	3.6	4.0
Depreciation, depletion and amortization	.1	.1	.2	.1
Taxes, other than income	---	---	.1	.1
	2.0	2.4	3.9	4.2
Operating loss	(2.0)	(2.4)	(3.9)	(4.2)
Loss from continuing operations	(1.4)	(1.8)	(4.1)	(1.6)
Income from discontinued operations, net of tax	7.4	3.3	12.6	4.4
Earnings	$ 6.0	$ 1.5	$ 8.5	$ 2.8
Net generation capacity (kW)*	437,600	437,600	437,600	437,600
Electricity produced and sold (thousand kWh)*	277,347	202,778	515,358	291,275

* Excludes equity method investments.

Three Months Ended June 30, 2007 and 2006 Earnings at the independent power production business increased $4.5 million due to increased income from discontinued operations, net of tax, of $4.1 million, largely due to:

· The absence in 2007 of depreciation expense related to assets held for sale
· Earnings related to an electric generating facility construction project in Hobbs, New Mexico

Six Months Ended June 30, 2007 and 2006 Earnings at the independent power production business increased $5.7 million due to increased income from discontinued operations, net of tax, of $8.2 million, largely due to:

- The absence in 2007 of depreciation expense related to assets held for sale
- Earnings related to an electric generating facility construction project in Hobbs, New Mexico
- Higher income at the Hardin Generating Station which was placed into service in March of 2006

Partially offsetting these increases were decreased income from continuing operations, largely due to higher interest expense and lower earnings from equity method investments. For more information, see Note 20.

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 June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
		(In millions)		
Other:				
Operating revenues	$ 2.4	$ 2.3	$ 4.9	$ 4.1
Operation and maintenance	1.8	1.8	3.9	3.0
Depreciation, depletion and amortization	.3	.2	.6	.5
Taxes, other than income	---	.1	---	.1
Intersegment transactions:				
Operating revenues	$ 76.9	$ 72.2	$ 171.1	$ 180.2
Purchased natural gas sold	69.8	65.0	157.1	166.3
Operation and maintenance	7.1	7.2	14.0	13.9

For further information on intersegment eliminations, see Note 16.

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 increases 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 $2.15 to $2.35. This earnings per share guidance range includes the estimated third quarter gain of approximately $90 million (after tax) on the sale of the domestic independent power production assets and earnings from discontinued operations. Excluding the estimated gain, earnings per share guidance for 2007 has been increased to a range of $1.65 to $1.85, an increase from prior guidance of $1.55 to $1.75.

- The Company expects the percentage of 2007 earnings per common share, diluted, by quarter, including the gain on the sale of the domestic independent power production assets, to be in the following approximate ranges:
  - Third quarter - 45 percent to 50 percent
  - Fourth quarter - 15 percent to 20 percent

· 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. A filing in North Dakota for prudence approval of Big Stone II was made in November 2006, with an order expected by September 2007. The Company would own approximately 116 MW of Big Stone II. The plant is projected to be on line in 2012. A final decision on the project will be made once major permits are issued, which is expected to occur in early 2008.

· 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 18.

Natural gas distribution

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

· For more information on the acquisition of Cascade, see Note 20.

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 June 30, 2007, was approximately $765 million compared to $523 million at June 30, 2006.

Pipeline and energy services

· Based on anticipated demand, additional incremental expansions to the Grasslands Pipeline are forecasted over the next few years. The next expansion, to 138,000 Mcf per day, is scheduled for completion in late 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 5 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 in the range of 5 percent to 7 percent. The updated guidance reflects delayed infrastructure installation in the Company's Powder River coalbed and South Texas operations, spring weather conditions which delayed completion and work over activities, and longer dewatering time required on the coalbed wells drilled in 2006.

· The Company expects to drill approximately 250 wells in 2007, dependent on the timely receipt of regulatory approvals. Previous guidance assumed the drilling of one coalbed well for each coal seam targeted. Revised guidance is based on the commingling of multiple coal seams into a single well bore, reducing 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 200,000 Mcf equivalent to 210,000 Mcf equivalent per day.

· Earnings guidance reflects estimated natural gas prices for August 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, more than three-fourths of 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 July through December 2007 in the range of $63 to $68 per barrel.

· The Company has hedged approximately 35 percent to 40 percent of its estimated natural gas production and less than five percent of its estimated oil production for the last six months of 2007. For 2008, the Company has hedged approximately 25 percent to 30 percent of its estimated natural gas production and less than five percent of its estimated oil production. The hedges that are in place as of August 3, 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	7/07 - 10/07	922,500	$7.16
Natural Gas	Ventura	7/07 - 12/07	920,000	$8.00-$11.91
Natural Gas	Ventura	7/07 - 12/07	460,000	$8.00-$11.80
Natural Gas	Ventura	7/07 - 12/07	460,000	$8.00-$11.75
Natural Gas	Ventura	7/07 - 12/07	920,000	$7.50-$10.55
Natural Gas	CIG	7/07 - 12/07	920,000	$7.40
Natural Gas	CIG	7/07 - 12/07	920,000	$7.405
Natural Gas	Ventura	7/07 - 12/07	736,000	$8.25-$10.80
Natural Gas	CIG	7/07 - 12/07	460,000	$7.50-$9.12
Natural Gas	Ventura	7/07 - 12/07	920,000	$8.29
Natural Gas	Ventura	7/07 - 12/07	920,000	$7.85-$9.70
Natural Gas	Ventura	7/07 - 12/07	1,840,000	$7.67
Natural Gas	NYMEX	7/07 - 12/07	920,000	$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	Ventura	11/08 - 12/08	610,000	$8.85
Crude Oil	NYMEX	9/07 - 12/07	51,850	$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 has 1.2 billion tons of strategically located aggregate reserves, a key element of its vertical integration strategy.

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

- Work backlog as of June 30, 2007, of approximately $662 million includes a higher expected average margin than the backlog of $763 million at June 30, 2006.

Independent power production

- For information regarding the sale of the domestic independent power production assets, see Note 20.

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Note 10, 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 six months of 2007 decreased $52.9 million from the comparable 2006 period, the result of increased cash used related to discontinued operations of $52.1 million, largely due to an increase in quarterly income tax payments due to the estimated gain on the sale of the domestic independent power production assets. In addition, cash used for working capital requirements increased $21.6 million, largely due to the effects of:

- Lower accounts payable, largely at the construction services and construction materials and mining businesses
- The timing of natural gas costs recoverable through rate adjustments at the natural gas distribution business

Partially offsetting the decrease in cash flows from operating activities were:

- Decreased receivables at the construction services and construction materials and mining businesses, partially offset by higher receivables at the natural gas distribution and natural gas and oil production businesses, due to fluctuations in natural gas prices
-

Higher depreciation, depletion and amortization expense of $14.0 million and higher deferred income taxes of $8.8 million

Investing activities Cash flows used in investing activities in the first six months of 2007 decreased $162.0 million compared to the comparable 2006 period, the result of:

- A decrease in cash flows used for acquisitions of $108.9 million, largely at the natural gas and oil production business
- Decreased cash used in investing activities from discontinued operations of $36.7 million, largely the result of lower capital expenditures related to the Hardin Generating Facility and a decrease in cash flows used for acquisitions, both of which are related to the independent power production business
- Lower investments of $22.5 million, primarily the result of the sale of the Trinity Generating Facility during the first quarter of 2007

Financing activities Cash flows provided by financing activities in the first six months of 2007 decreased $125.9 million compared to the comparable 2006 period, primarily the result of a decrease in the issuance of long-term debt of $149.1 million, partially offset by a decrease in the repayment of long-term debt of $12.1 million and an increase in the issuance of common stock of $13.1 million.

Defined benefit pension plans

There were no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2006 Annual Report. For further information, see Note 17 and Part II, Item 7 in the 2006 Annual Report.

Capital expenditures

Net capital expenditures for the first six months of 2007 were $245.0 million. Net capital expenditures are estimated to be approximately $1.1 billion for 2007, excluding proceeds from the sale of the domestic independent power production assets. Estimated 2007 net capital expenditures also exclude potential future acquisitions and proceeds related to the disposal of unidentified 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 46 percent of estimated 2007 net capital expenditures noted above 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 June 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 June 30, 2007. The credit agreement supports the Company's $100 million commercial paper program. Under the Company's commercial paper program, $18.5 million was outstanding at June 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 was 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 discussed above, 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 June 30, 2007. In the event the Company does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued, as previously described.

On June 29, 2007, the Company entered into a term loan agreement to be used in connection with the Cascade acquisition. For more information, see Note 20.

The term loan agreement contains customary covenants and default provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (i) the ratio of funded debt to total capitalization (on a consolidated basis) to be greater than 65 percent or (ii) the ratio of funded debt to capitalization (determined with respect to the Company only, excluding subsidiaries) to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company only, excluding subsidiaries), for the twelve month period ended each fiscal quarter, to be greater than 2.5 to 1.

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 June 30, 2007, the Company could have issued approximately $493 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 June 30, 2007 and December 31, 2006, respectively. Additionally, the Company's first mortgage bond interest coverage was 35.1 times and 26.0 times for the 12 months ended June 30, 2007 and December 31, 2006, respectively. Common stockholders' equity as a percent of total capitalization (net of long-term debt due within one year) was 65 percent at both June 30, 2007 and December 31, 2006.

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 June 30, 2007, the Company had $50.5 million of first mortgage bonds outstanding, $30 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 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 June 30, 2007, the only such debt outstanding under the Indenture was $30 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 June 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 at June 30, 2007. Under the Centennial commercial paper program, $283.8 million was outstanding at June 30, 2007. The 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 June 30, 2007, $42.6 million of letters of credit were outstanding, as discussed in Note 19, of which $28.5 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, $468.5 million was outstanding at June 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 was 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 June 30, 2007. In the event Centennial or such subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued as previously described.

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 June 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 June 30, 2007. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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 19.

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 19.

Contractual obligations and commercial commitments
There were no material changes in the Company's contractual obligations relating to long-term debt, operating leases and purchase commitments from those reported in the 2006 Annual Report.

For more information on contractual obligations and commercial commitments, see Part II, Item 7 in the 2006 Annual Report.

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. At June 30, 2007, Fidelity held natural gas swap and collar derivative instruments designated as cash flow hedging instruments and had no outstanding oil derivative instruments. For more information on derivative instruments and commodity price risk, see Part II, Item 7A in the 2006 Annual Report, and Notes 11 and 14.

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

	(Notional amount and fair value in thousands)		
	Weighted Average Fixed Price (Per MMBtu)	Forward Notional Volume (In MMBtu's)	Fair Value
Natural gas swap agreements maturing in 2007	$7.66	5,767	$9,263
Natural gas swap agreements maturing in 2008	$8.41	8,228	$3,265

	Weighted Average Floor/Ceiling Price (Per MMBtu)	Forward Notional Volume (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2007	$7.83/$10.26	6,406	$ 7,578
Natural gas collar agreements maturing in 2008	$7.27/$8.32	8,690	$(1,194)

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 June 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 June 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, that the Company’s assets are safeguarded against unauthorized or improper use and that 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 19, 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. 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.

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

Between April 1, 2007 and June 30, 2007, the Company issued 1,295 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 a prior 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.

The following table includes information with respect to the issuer's purchase of equity securities:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
April 1 through April 30, 2007	36,668	$31.05		
May 1 through May 31, 2007				
June 1 through June 30, 2007				
Total	36,668			

(1) Represents 218 shares of common stock withheld by the Company to pay taxes in connection with the vesting of shares granted pursuant to a compensation plan and 36,450 shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors.

(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to repurchase equity securities.

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: August 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.

4	MDU Resources Group, Inc. Term Loan Agreement, dated June 29, 2007, among MDU Resources Group, Inc., Wells Fargo Bank, National Association, as Administrative Agent, and The Other Financial Institutions party thereto
+10	Consulting Agreement, dated July 2, 2007, by and between Williston Basin Interstate Pipeline Company and John K. Castleberry
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

+ Management contract, compensatory plan or arrangement.

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.