

MDU RESOURCES GROUP INC  
Form 10-Q  
May 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 March 31, 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  
(State or other jurisdiction of incorporation  
or organization)

41-0423660  
(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 May 1, 2007: 181,833,102 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
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)
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
Hart-Scott-Rodino Act	Hart-Scott-Rodino Antitrust Improvements Act
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
MBbbls	Thousands of 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)
MW	Megawatt

ND Health Department	North Dakota Department of Health
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.

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.

On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 4.

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**PART I -- FINANCIAL INFORMATION**

**ITEM 1. FINANCIAL STATEMENTS**

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

Three Months Ended

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	March 31,	
	2007	2006
	<i>(In thousands, except per share amounts)</i>	
<b>Operating revenues:</b>		
Electric, natural gas distribution and pipeline and energy services	\$ 268,011	\$ 291,052
Construction services, natural gas and oil production, construction materials and mining, and other	519,480	512,467
	787,491	803,519
<b>Operating expenses:</b>		
Fuel and purchased power	17,118	16,135
Purchased natural gas sold	98,835	126,960
Operation and maintenance:		
Electric, natural gas distribution and pipeline and energy services	44,654	37,288
Construction services, natural gas and oil production, construction materials and mining, independent power production and other	445,851	438,847
Depreciation, depletion and amortization	69,802	60,981
Taxes, other than income	32,262	32,240
	708,522	712,451
<b>Operating income</b>	78,969	91,068
<b>Earnings from equity method investments</b>	2,054	3,202
<b>Other income</b>	1,332	2,380
<b>Interest expense</b>	17,376	14,052
<b>Income before income taxes</b>	64,979	82,598
<b>Income taxes</b>	23,572	30,153
<b>Income from continuing operations</b>	41,407	52,445
<b>Income from discontinued operations, net of tax (Note 3)</b>	5,255	801
<b>Net income</b>	46,662	53,246
<b>Dividends on preferred stocks</b>	171	171
<b>Earnings on common stock</b>	\$ 46,491	\$ 53,075
<b>Earnings per common share -- basic</b>		
Earnings before discontinued operations	\$ .23	\$ .29
Discontinued operations, net of tax	.03	.01
Earnings per common share -- basic	\$ .26	\$ .30
<b>Earnings per common share -- diluted</b>		
Earnings before discontinued operations	\$ .23	\$ .29
Discontinued operations, net of tax	.02	---
Earnings per common share -- diluted	\$ .25	\$ .29
<b>Dividends per common share</b>	\$ .1350	\$ .1267
<b>Weighted average common shares outstanding -- basic</b>	181,341	179,823

**Weighted average common shares outstanding -- diluted** 182,337 180,915

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

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

	March 31, 2007	March 31, 2006	December 31, 2006
	<i>(In thousands, except shares and per share amounts)</i>		
<b>ASSETS</b>			
<b>Current assets:</b>			
Cash and cash equivalents	\$ 51,574	\$ 107,970	\$ 73,078
Receivables, net	548,542	542,746	622,478
Inventories	206,250	171,474	204,440
Deferred income taxes	2,702	10,286	---
Prepayments and other current assets	96,766	70,818	81,083
Current assets held for sale	23,871	10,180	12,656
	929,705	913,474	993,735
<b>Investments</b>	133,454	103,404	155,111
<b>Property, plant and equipment</b>	4,850,268	4,293,811	4,727,725
Less accumulated depreciation, depletion and amortization	1,799,770	1,575,110	1,735,302
	3,050,498	2,718,701	2,992,423
<b>Deferred charges and other assets:</b>			
Goodwill	226,937	214,967	224,298
Other intangible assets, net	17,929	10,222	22,802
Other	107,639	106,020	103,840
Noncurrent assets held for sale	410,282	415,596	411,265
	762,787	746,805	762,205
	\$ 4,876,444	\$ 4,482,384	\$ 4,903,474
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>			
<b>Current liabilities:</b>			
Long-term debt due within one year	\$ 83,446	\$ 101,707	\$ 84,034
Accounts payable	244,059	225,611	289,836
Taxes payable	67,223	62,466	54,290
Deferred income taxes	---	---	5,969
Dividends payable	24,693	22,964	24,606
Other accrued liabilities	143,045	138,392	180,327
Current liabilities held for sale	19,150	6,397	14,900
	581,616	557,537	653,962
<b>Long-term debt</b>	1,155,117	1,134,889	1,170,548
<b>Deferred credits and other liabilities:</b>			
Deferred income taxes	556,522	525,755	546,602
Other liabilities	357,353	278,589	336,916
Noncurrent liabilities held for sale	33,680	29,670	30,533
	947,555	834,014	914,051
<b>Commitments and contingencies</b>			

**Stockholders' equity:**

Preferred stocks	15,000	15,000	15,000
Common stockholders' equity:			
Common stock			
Shares issued -- \$1.00 par value			
182,319,441 at March 31, 2007,			
120,290,305 at March 31, 2006 and			
181,557,543 at December 31, 2006	182,319	120,290	181,558
Other paid-in capital	891,990	913,026	874,253
Retained earnings	1,126,270	914,899	1,104,210
Accumulated other comprehensive loss	(19,797)	(3,645)	(6,482)
Treasury stock at cost - 538,921 shares			
at March 31, 2007 and December 31, 2006			
and 359,281 shares at March 31, 2006	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,177,156	1,940,944	2,149,913
Total stockholders' equity	2,192,156	1,955,944	2,164,913
	\$ 4,876,444	\$ 4,482,384	\$ 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)**

	Three Months Ended March 31,	
	2007	2006
	<i>(In thousands)</i>	
<b>Operating activities:</b>		
Net income	\$ 46,662	\$ 53,246
Income from discontinued operations, net of tax	5,255	801
Income from continuing operations	41,407	52,445
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	69,802	60,981
Earnings, net of distributions, from equity method investments	1,056	(1,017)
Deferred income taxes	13,686	5,850
Changes in current assets and liabilities, net of acquisitions:		
Receivables	79,780	56,859
Inventories	(1,761)	(260)
Other current assets	(37,931)	(24,777)
Accounts payable	(48,729)	(25,553)
Other current liabilities	(25,951)	10,521
Other noncurrent changes	9,174	(358)
Net cash provided by continuing operations	100,533	134,691
Net cash provided by (used in) discontinued operations	5,596	(2,900)
<b>Net cash provided by operating activities</b>	<b>106,129</b>	<b>131,791</b>



**Investing activities:**

Capital expenditures	(123,758)	(115,612)
Acquisitions, net of cash acquired	(320)	---
Net proceeds from sale or disposition of property	3,202	8,813
Investments	17,113	(4,408)
Net cash used in continuing operations	(103,763)	(111,207)
Net cash used in discontinued operations	(839)	(21,276)
<b>Net cash used in investing activities</b>	<b>(104,602)</b>	<b>(132,483)</b>

**Financing activities:**

Issuance of long-term debt	8,765	113,006
Repayment of long-term debt	(24,692)	(91,441)
Proceeds from issuance of common stock	13,933	1,698
Dividends paid	(24,607)	(22,950)
Tax benefit on stock-based compensation	3,566	2,851
Net cash provided by (used in) continuing operations	(23,035)	3,164
Net cash provided by discontinued operations	---	---
<b>Net cash provided by (used in) financing activities</b>	<b>(23,035)</b>	<b>3,164</b>
<b>Effect of exchange rate changes on cash and cash equivalents</b>	<b>4</b>	<b>---</b>
<b>Increase (decrease) in cash and cash equivalents</b>	<b>(21,504)</b>	<b>2,472</b>
Cash and cash equivalents -- beginning of year	73,078	105,498
Cash and cash equivalents -- end of period	\$ 51,574	\$ 107,970

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

**MDU RESOURCES GROUP, INC.**  
**NOTES TO CONSOLIDATED**  
**FINANCIAL STATEMENTS**

**March 31, 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 the domestic independent power production assets, including CEM, are presented as discontinued operations. For more information on the pending sale of the domestic independent power production assets, see Note 21.

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.

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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 March 31,		
	2007		2006
	(In thousands)		
Operating revenues	\$	250	\$ 509
Loss from discontinued operations before income tax benefit		(75)	(473)
Income tax benefit		(44)	(149)
Loss from discontinued operations, net of tax	\$	(31)	\$ (324)

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

	Three Months Ended March 31,		
	2007		2006
	(In thousands)		
Operating revenues	\$	34,596	\$ 11,266
Income from discontinued operations before income tax expense (benefit)		7,390	492
Income tax expense (benefit)		2,104	(633)
Income from discontinued operations, net of tax	\$	5,286	\$ 1,125

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:

	March 31, 2007	March 31, 2006	December 31, 2006
	(In thousands)		
Cash and cash equivalents	\$ 9,991	\$ 1,779	\$ 1,878
Receivables, net	6,697	5,251	8,307
Inventories	596	1,007	490
Prepayments and other current assets	6,587	2,143	1,981
Total current assets held for sale	\$ 23,871	\$ 10,180	\$ 12,656
Net property, plant and equipment	\$ 391,168	\$ 386,387	\$ 390,679
Goodwill	11,167	15,472	11,167
Other intangible assets, net	7,241	7,647	7,162
Other	706	6,090	2,257
Total noncurrent assets held for sale	\$ 410,282	\$ 415,596	\$ 411,265
Accounts payable	\$ 13,717	\$ 5,763	\$ 11,557
Other accrued liabilities	5,433	634	3,343
Total current liabilities held for sale	\$ 19,150	\$ 6,397	\$ 14,900
Deferred income taxes	\$ 29,664	\$ 27,517	\$ 27,956

Other liabilities		4,016		2,153		2,577
Total noncurrent liabilities held for sale	\$	33,680	\$	29,670	\$	30,533

#### 4. **Common stock split**

On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split to be effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on July 26, 2006, to common stockholders of record on July 12, 2006. Certain common stock information appearing in the accompanying consolidated financial statements has been restated in accordance with accounting principles generally accepted in the United States of America to give retroactive effect to the stock split. Additionally, preference share purchase rights have been appropriately adjusted to reflect the effects of the split.

#### 5. **Allowance for doubtful accounts**

The Company's allowance for doubtful accounts as of March 31, 2007 and 2006, and December 31, 2006, was \$8.0 million, \$7.9 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 \$3.5 million, \$4.7 million and \$32.6 million at March 31, 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 March 31, 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 \$95.2 million, \$89.3 million and \$88.1 million; materials and supplies of \$75.4 million, \$55.1 million and \$54.1 million; and other inventories of \$32.1 million, \$22.4 million and \$29.6 million, as of March 31, 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 months ended March 31, 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:

	Three Months Ended	
	March 31,	
	2007	2006
	(In thousands)	
Interest, net of amount capitalized	\$ 17,367	\$ 12,332
Income taxes	\$ 3,150	\$ 5,888

#### 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 March 31,	
	2007	2006
	(In thousands)	
Net income	\$ 46,662	\$ 53,246
Other comprehensive income (loss):		
Net unrealized gain (loss) on derivative instruments qualifying as hedges:		
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of \$6,383 and \$14,639 in 2007 and 2006, respectively	(10,196)	23,385
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of \$3,271 and \$4,249 in 2007 and 2006, respectively	5,226	(6,787)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(15,422)	30,172
Foreign currency translation adjustment	2,107	(1)
	(13,315)	30,171
Comprehensive income	\$ 33,347	\$ 83,417

#### 12. **Equity method investments**

The Company's equity method investments at March 31, 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. The Company has entered into an agreement to sell its ownership interest in Hartwell. For more information, see Note 21.

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 March 31, 2007 and 2006, and December 31, 2006, the Company's equity method investments had total assets of \$457.6 million, \$233.1 million and \$583.6 million, respectively, and long-term debt of \$275.5 million, \$154.8 million and \$321.5 million, respectively. The Company's investment in its equity method investments was approximately \$79.6 million, \$43.0 million and \$102.0 million, including undistributed earnings of \$930,000, \$4.5 million and \$8.5 million, at March 31, 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:

Three Months Ended March 31, 2007	Balance as of January 1, 2007	Goodwill Acquired During the Year* (In thousands)	Balance as of March 31, 2007
Electric	\$ ---	\$ ---	\$ ---
Natural gas distribution	---	---	---
Construction services	86,942	3,550	90,492
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and mining	136,197	(911)	135,286
Independent power production	---	---	---
Other	---	---	---
<b>Total</b>	<b>\$ 224,298</b>	<b>\$ 2,639</b>	<b>\$ 226,937</b>
Three Months Ended March 31, 2006	Balance as of January 1, 2006	Goodwill Acquired During the Year* (In thousands)	Balance as of March 31, 2006
Electric	\$ ---	\$ ---	\$ ---
Natural gas distribution	---	---	---
Construction services	80,970	137	81,107
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and mining	133,264	(563)	132,701
Independent power production	---	---	---
Other	---	---	---

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Total	\$	215,393	\$	(426)	\$	214,967
		Balance		Goodwill		Balance
		as of		Acquired		as of
Year Ended		January 1,		During the		December 31,
December 31, 2006		2006		Year*		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:

		March 31,		March 31,		December 31,
		2007		2006		2006
				(In thousands)		
Amortizable intangible assets:						
Customer relationships	\$	13,959	\$	4,400	\$	13,030
Accumulated amortization		(2,628)		(620)		(1,890)
		11,331		3,780		11,140
Noncompete agreements		5,045		11,784		12,886
Accumulated amortization		(1,873)		(8,680)		(8,540)
		3,172		3,104		4,346
Acquired contracts		1,186		3,504		8,307
Accumulated amortization		(1,118)		(3,150)		(4,646)
		68		354		3,661
Other		4,842		3,162		5,062
Accumulated amortization		(1,484)		(702)		(1,407)
		3,358		2,460		3,655
Unamortizable intangible assets		---		524		---
Total	\$	17,929	\$	10,222	\$	22,802

The unamortizable intangible assets at March 31, 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 months ended March 31, 2007 and 2006, and for the year ended December 31, 2006, was \$1.0 million, \$863,000 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 \$6.6 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 March 31, 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 March 31, 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 months ended March 31, 2007 and 2006, the amount of hedge ineffectiveness was immaterial. For the three months ended March 31, 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 March 31, 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 21 months. The Company estimates that over the next 12 months net gains of approximately \$6.0 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 transmission and natural resource-based projects.

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 owns, builds and operates electric generating facilities in the United States and has domestic and international investments including transmission and natural resource-based projects. Electric capacity and energy produced at its power plants primarily are sold under mid- and long-term contracts to nonaffiliated entities. For more information regarding the discontinued operations of this segment, see Note 3.

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 March 31, 2007	External Operating Revenues	Inter- segment Operating Revenues (In thousands)	Earnings on Common Stock
Electric	\$ 47,104	\$ ---	\$ 3,784
Natural gas distribution	136,061	---	6,145

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Pipeline and energy services	84,846	28,292	5,710
	268,011	28,292	15,639
Construction services	236,638	125	7,234
Natural gas and oil production	55,269	63,311	30,621
Construction materials and mining	227,573	---	(9,796)
Independent power production	---	---	2,517
Other	---	2,440	276
	519,480	65,876	30,852
Intersegment eliminations	---	(94,168)	---
Total	\$ 787,491	\$ ---	\$ 46,491

Three Months Ended March 31, 2006	External Operating Revenues	Inter- segment Operating Revenues (In thousands)	Earnings on Common Stock
Electric	\$ 45,030	\$ ---	\$ 3,797
Natural gas distribution	152,279	---	5,321
Pipeline and energy services	93,743	32,806	4,569
	291,052	32,806	13,687
Construction services	223,685	110	5,398
Natural gas and oil production	55,098	73,292	41,258
Construction materials and mining	233,684	---	(8,874)
Independent power production	---	---	1,342
Other	---	1,769	264
	512,467	75,171	39,388
Intersegment eliminations	---	(107,977)	---
Total	\$ 803,519	\$ ---	\$ 53,075

The pipeline and energy services segment recognized a loss from discontinued operations, net of tax, of \$31,000 and \$324,000 for the three months ended March 31, 2007 and 2006, respectively. The independent power production segment recognized income from discontinued operations, net of tax, of \$5.3 million and \$1.1 million for the three months ended March 31, 2007 and 2006, respectively. Excluding the loss from discontinued operations at pipeline and energy services, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings (loss) 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 March 31,	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	\$ 2,250	\$ 2,301	\$ 533	\$ 471
Interest cost	4,141	4,074	938	929

Expected return on assets	(5,070)	(4,718)	(1,093)	(925)
Amortization of prior service cost	209	256	11	11
Amortization of net actuarial (gain) loss	74	509	(313)	(84)
Amortization of net transition obligation (asset)	---	(1)	531	531
Net periodic benefit cost, including amount capitalized	1,604	2,421	607	933
Less amount capitalized	151	156	52	46
Net periodic benefit cost	\$ 1,453	\$ 2,265	\$ 555	\$ 887

In addition to the qualified plan defined pension benefits reflected in the table, the Company 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 an 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 months ended March 31, 2007 and 2006, was \$1.8 million and \$2.0 million, respectively.

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

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 November 2005 Order. In April 2006, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision dated November 2005 and its Order on Rehearing issued in April 2006. 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. Fidelity cannot predict what the final terms of the SEIS will be. The final SEIS is scheduled for release in the summer of 2007.

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 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 it 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 are currently briefing cross motions for summary judgment.

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 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 March 31, 2007, Williston Basin estimated approximately 7.5 Bcf of storage gas had been diverted from the EBSR as a result of Howell and Anadarko's drilling and production.

Williston Basin filed suit in Montana Federal District Court in January 2006, seeking to recover unspecified damages from Howell and Anadarko, and to enjoin Howell and Anadarko's present and future production from specified wells in and near the EBSR. The Montana Federal District Court entered an Order in July 2006, dismissing the case for lack of subject matter jurisdiction. Williston Basin filed a Notice of Appeal to the Ninth Circuit in July 2006.

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 district court is expected to rule on the special master's recommendation in the first half of 2007. A trial in Wyoming state district court is scheduled for October 22, 2007.

As noted above, Williston Basin estimates that as of March 31, 2007, Howell and Anadarko had diverted approximately 7.5 Bcf from the EBSR. Williston Basin believes Howell and Anadarko continue to divert gas from the EBSR and Williston Basin continues to monitor and analyze the situation. At trial, Williston Basin will seek recovery based on the amount of gas that has been and continues to be diverted as well as on the amount of gas that must be recovered as a result of the equalization of the pressures of various interconnected geological formations.

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 administrative action.

### **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 that 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 from approximately two 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.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas price swap and collar agreement obligations. Fidelity's obligations at March 31, 2007, were \$3.4 million. 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 March 31, 2007, expire in 2007 and 2008; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. The amount outstanding by Fidelity was reflected on the Consolidated Balance Sheets at March 31, 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 natural gas transportation and sales agreements, electric power supply agreements, construction contracts, gathering contracts, a conditional purchase agreement and

certain other guarantees. At March 31, 2007, the fixed maximum amounts guaranteed under these agreements aggregated \$175.3 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate \$14.9 million in 2007; \$86.0 million in 2008; \$3.1 million in 2009; \$30.3 million in 2010; \$23.0 million in 2011; \$12.7 million in 2012; \$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 March 31, 2007, has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was \$641,000 and was reflected on the Consolidated Balance Sheet at March 31, 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 March 31, 2007, the fixed maximum amounts guaranteed under these letters of credit aggregated \$42.5 million. In 2007 and 2008, \$15.6 million and \$26.9 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at March 31, 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 March 31, 2007, the fixed maximum amounts guaranteed under these agreements aggregated \$25.1 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate \$2.2 million in 2007, \$2.9 million in 2008 and \$20.0 million in 2009. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was \$1.7 million, which was not reflected on the Consolidated Balance Sheet at March 31, 2007, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial and Knife River have issued guarantees to third parties related to the Company's routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation 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 March 31, 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 March 31, 2007, approximately \$466 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

## 20. **Pending acquisition**

In July 2006, the Company entered into a definitive merger agreement to acquire Cascade, subject to approval of Cascade's shareholders and various regulatory authorities, as well as antitrust clearance under the Hart-Scott-Rodino Act, and the satisfaction of other customary closing conditions. In October 2006, shareholders of Cascade approved the merger agreement. In November 2006, the Company obtained clearance under the Hart-Scott-Rodino Act. In March 2007, regulatory approvals were received from the North Dakota Public Service Commission and the Minnesota Public Utilities Commission.

On May 1, 2007, the Company filed stipulations with the Oregon Public Utility Commission to resolve pending proceedings before that commission. The filed stipulations relate to the application for approval of the pending merger with Cascade, as well as a pending show cause proceeding (applicable to Cascade's level of rates) in Oregon, which



commenced in August 2006. Parties to the stipulations include the commission's staff as well as various interveners. In addition, the Washington Utilities and Transportation Commission staff, various interveners, Cascade and the Company have reached a settlement in principle of all issues in the merger proceeding pending before the Washington Utilities and Transportation Commission and a settlement stipulation is expected to be filed by mid-May 2007. The Oregon and Washington stipulations include certain commitments and rate credits applicable to the approval of the merger and are subject to the approval of the respective commissions.

Regulatory approvals in Oregon and Washington are anticipated by mid-year 2007. 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.

#### 21. **Pending sale**

On April 25, 2007, Centennial Resources entered into a definitive purchase and sale agreement with Montana Acquisition Company LLC. Under the agreement, the Company will sell its domestic independent power production business consisting of Centennial Power and CEM to Montana Acquisition Company LLC.

The transaction is valued at \$636 million, which includes the assumption of approximately \$36 million of project-related debt. The closing of the sale is expected to occur in June 2007 and is subject to the receipt of regulatory approvals and fulfillment of other conditions established in the agreement. Proceeds from the sale will be used to fund the Company's acquisition of Cascade and will provide additional cash for growth opportunities that exist in the Company's core lines of business.

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

### **OVERVIEW**

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

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

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

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

### **Key Strategies and Challenges**

#### ***Electric and Natural Gas Distribution***

**Strategy** Provide competitively priced energy to customers while working with them to ensure efficient usage. Both the electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations and through selected acquisitions of companies and properties at prices that will provide 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; and increased competition from many of the larger 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 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 likely to be affected by the slowdown in housing, which should be partially mitigated by increased commercial spending.

### ***Independent Power Production***

**Strategy** Divest domestic assets due to the increased market demand for independent power production assets, combined with the Company's desire to efficiently fund its future capital needs.

**Challenges** Overall business challenges for this segment include: the risks and uncertainties associated with the sale of the domestic assets; construction, startup and operation of power plant facilities; and 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 March 31,		
	2007		2006
	<i>(Dollars in millions, where applicable)</i>		
<b>Electric</b>	\$ 3.8	\$	3.8
<b>Natural gas distribution</b>	6.2		5.3
<b>Construction services</b>	7.2		5.4
<b>Pipeline and energy services</b>	5.7		4.9
<b>Natural gas and oil production</b>	30.6		41.3
<b>Construction materials and mining</b>	(9.8)		(8.9)
<b>Independent power production</b>	(2.8)		.2
<b>Other</b>	.3		.3
<b>Earnings before discontinued operations</b>	41.2		52.3
<b>Income from discontinued operations, net of tax</b>	5.3		.8
<b>Earnings on common stock</b>	\$ 46.5	\$	53.1
<b>Earnings per common share - basic:</b>			
<b>Earnings before discontinued operations</b>	\$ .23	\$	.29
<b>Discontinued operations, net of tax</b>	.03		.01
<b>Earnings per common share - basic</b>	\$ .26	\$	.30
<b>Earnings per common share - diluted:</b>			

<b>Earnings before discontinued operations</b>	\$	.23	\$	.29
<b>Discontinued operations, net of tax</b>		.02		---
<b>Earnings per common share - diluted</b>	\$	.25	\$	.29
<b>Return on average common equity for the 12 months ended</b>		14.8%		16.2%

**Three Months Ended March 31, 2007 and 2006** Consolidated earnings for the quarter ended March 31, 2007, decreased \$6.6 million from the comparable prior period. Earnings at the natural gas and oil production business decreased largely due to lower average realized natural gas prices of 11 percent, higher depreciation, depletion and amortization expense, and higher lease operating expense, partially offset by increased oil production of 24 percent. Partially offsetting the earnings decrease were higher construction margins in most regions at the construction services business.

## FINANCIAL AND OPERATING DATA

Below are key financial and operating data for each of the Company's businesses.

### Electric

		Three Months Ended March 31,	
		2007	2006
		<i>(Dollars in millions, where applicable)</i>	
<b>Operating revenues</b>	\$ 47.1	\$ 45.0	
<b>Operating expenses:</b>			
Fuel and purchased power		17.1	16.1
Operation and maintenance		15.1	14.0
Depreciation, depletion and amortization		5.6	5.3
Taxes, other than income		2.2	2.2
		40.0	37.6
<b>Operating income</b>		7.1	7.4
<b>Earnings</b>	\$	3.8	\$ 3.8
<b>Retail sales (million kWh)</b>		645.8	612.9
<b>Sales for resale (million kWh)</b>		44.1	166.4
<b>Average cost of fuel and purchased power per kWh</b>	\$	.024	\$ .020

**Three Months Ended March 31, 2007 and 2006** Electric earnings were unchanged at \$3.8 million. Higher retail sales volumes and margins were offset by lower sales for resale volumes and increased operation and maintenance expense, largely payroll related.

### Natural Gas Distribution

		Three Months Ended March 31,	
		2007	2006
		<i>(Dollars in millions, where applicable)</i>	
<b>Operating revenues</b>	\$	136.0	\$ 152.3
<b>Operating expenses:</b>			
Purchased natural gas sold		106.2	128.4
Operation and maintenance		15.5	11.8
Depreciation, depletion and amortization		2.5	2.4
Taxes, other than income		1.7	1.5
		125.9	144.1

<b>Operating income</b>		10.1		8.2
<b>Earnings</b>	\$	6.2	\$	5.3
<b>Volumes (MMdk):</b>				
Sales		15.9		14.2
Transportation		3.4		4.4
<b>Total throughput</b>		19.3		18.6
<b>Degree days (% of normal)*</b>		94%		85%
<b>Average cost of natural gas, including transportation, per dk</b>	\$	6.70	\$	9.01

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

**Three Months Ended March 31, 2007 and 2006** Earnings at the natural gas distribution business increased \$900,000, largely due to increased retail sales volumes, resulting from 10 percent colder weather than last year.

The pass-through of lower natural gas prices is reflected in the decrease in both sales revenues and purchased natural gas sold. The decrease in sales 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 March 31,		
		2007		2006
		<i>(In millions)</i>		
<b>Operating revenues</b>	\$	236.8	\$	223.8
<b>Operating expenses:</b>				
Operation and maintenance		211.7		202.8
Depreciation, depletion and amortization		3.5		3.5
Taxes, other than income		8.8		7.4
		224.0		213.7
<b>Operating income</b>		12.8		10.1
<b>Earnings</b>	\$	7.2	\$	5.4

**Three Months Ended March 31, 2007 and 2006** Construction services earnings increased \$1.8 million compared to the first quarter of the comparable prior period due to:

- Higher construction margins in most regions of \$1.7 million (after tax)
  - Increased equipment sales and rentals
- Earnings from acquisitions made since the comparable prior period, which contributed approximately 19 percent of the earnings increase

Partially offsetting this increase were higher general and administrative expenses of \$500,000 (after tax).

### Pipeline and Energy Services

		Three Months Ended March 31,		
		2007		2006
		<i>(Dollars in millions)</i>		
<b>Operating revenues:</b>				
Pipeline	\$	25.9	\$	20.7
Energy services		87.2		105.8
		113.1		126.5

<b>Operating expenses:</b>			
Purchased natural gas sold		79.6	97.8
Operation and maintenance		14.1	11.6
Depreciation, depletion and amortization		5.4	4.9
Taxes, other than income		2.7	2.5
		101.8	116.8
<b>Operating income</b>		11.3	9.7
<b>Income from continuing operations</b>		5.7	4.9
<b>Loss from discontinued operations, net of tax</b>		---	(.3)
<b>Earnings</b>	\$	5.7	\$ 4.6
<b>Transportation volumes (MMdk):</b>			
Montana-Dakota		8.0	8.0
Other		20.6	18.1
		28.6	26.1
<b>Gathering volumes (MMdk)</b>		22.1	21.7

*Three Months Ended March 31, 2007 and 2006* Pipeline and energy services experienced an increase in earnings of \$1.1 million due to:

- Higher storage services revenue of \$1.9 million (after tax)
- Higher transportation and gathering volumes of \$1.0 million (after tax)

Partially offsetting this increase were higher operation and maintenance expense related to the natural gas storage litigation and higher 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 March 31,	
		2007	2006
		<i>(Dollars in millions, where applicable)</i>	
<b>Operating revenues:</b>			
Natural gas	\$	94.0	\$ 105.4
Oil		24.6	21.0
Other		---	2.0
		118.6	128.4
<b>Operating expenses:</b>			
Purchased natural gas sold		.3	2.0
Operation and maintenance:			
Lease operating costs		15.5	11.9
Gathering and transportation		4.5	4.7
Other		8.4	7.4
Depreciation, depletion and amortization		29.8	24.5
Taxes, other than income:			
Production and property taxes		8.9	9.9
Other		.2	.2
		67.6	60.6
<b>Operating income</b>		51.0	67.8
<b>Earnings</b>	\$	30.6	\$ 41.3
<b>Production:</b>			

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Natural gas (MMcf)		15,440		15,362
Oil (MBbls)		556		450
<b>Average realized prices (including hedges):</b>				
Natural gas (per Mcf)	\$	6.08	\$	6.86
Oil (per barrel)	\$	44.34	\$	46.71
<b>Average realized prices (excluding hedges):</b>				
Natural gas (per Mcf)	\$	5.74	\$	6.90
Oil (per barrel)	\$	44.34	\$	47.65
<b>Production costs, including taxes, per equivalent Mcf:</b>				
Lease operating costs	\$	.83	\$	.66
Gathering and transportation		.24		.26
Production and property taxes		.47		.55
	\$	1.54	\$	1.47

**Three Months Ended March 31, 2007 and 2006** The natural gas and oil production business experienced a \$10.7 million decrease in earnings due to:

- Lower average realized gas prices of 11 percent and lower average realized oil prices of 5 percent
- Higher depreciation, depletion and amortization expense of \$3.3 million (after tax) due to higher depletion rates and increased production
  - Higher lease operating expense of \$2.1 million (after tax), largely acquisition and CBNG-related costs
- Increased general and administrative expense of \$600,000 (after tax), primarily due to higher payroll related costs

Partially offsetting the decrease were increased oil production of 24 percent and natural gas production of 1 percent, largely due to increased production in the Rocky Mountain region, including the Baker and Bowdoin fields and the May 2006 Big Horn acquisition, as well as from the South Texas properties.

**Construction Materials and Mining**

	Three Months Ended March 31,		
	2007		2006
	<i>(Dollars in millions)</i>		
<b>Operating revenues</b>	\$	227.6	\$ 233.7
<b>Operating expenses:</b>			
Operation and maintenance		208.9	215.7
Depreciation, depletion and amortization		22.6	20.1
Taxes, other than income		7.7	8.4
		239.2	244.2
<b>Operating loss</b>		(11.6)	(10.5)
<b>Loss</b>	\$	(9.8)	\$ (8.9)
<b>Sales (000's):</b>			
Aggregates (tons)		5,557	6,084
Asphalt (tons)		336	333
Ready-mixed concrete (cubic yards)		626	711

**Three Months Ended March 31, 2007 and 2006** Construction materials and mining experienced a normal seasonal first quarter loss of \$9.8 million. The seasonal loss increased by \$900,000 from \$8.9 million in 2006. The increased seasonal loss was due to:

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Lower earnings from ready-mixed concrete operations of \$2.1 million (after tax), primarily the result of lower volumes

- Higher depreciation, depletion and amortization of \$1.2 million (after tax), largely the result of higher property, plant and equipment balances
  - Losses from companies acquired since the comparable prior period of \$700,000 (after tax)

Partially offsetting the decrease were increased earnings from construction of \$3.1 million (after tax) due to higher margins.

### Independent Power Production

	Three Months Ended March 31,			
	2007		2006	
	<i>(Dollars in millions)</i>			
<b>Operating revenues</b>	\$	---	\$	---
<b>Operating expenses:</b>				
Operation and maintenance		1.7		1.8
Depreciation, depletion and amortization		.1		.1
Taxes, other than income		.1		.1
		1.9		2.0
<b>Operating loss</b>		(1.9)		(2.0)
<b>Income (loss) from continuing operations</b>		(2.8)		.2
<b>Income from discontinued operations, net of tax</b>		5.3		1.1
<b>Earnings</b>	\$	2.5	\$	1.3
<b>Net generation capacity (kW)*</b>		437,600		389,600
<b>Electricity produced and sold (thousand kWh)*</b>		238,011		88,497

\* Excludes equity method investments.

*Three Months Ended March 31, 2007 and 2006* Earnings at the independent power production business increased \$1.2 million due to increased income from discontinued operations, net of tax, of \$4.2 million, largely due to:

- Higher income at the Hardin Generating Station which was placed in service in March 2006
  - 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

Partially offsetting this increase was decreased income from continuing operations, largely due to lower earnings from equity method investments and higher interest expense. The higher interest expense is primarily from debt related to the domestic assets held for sale. For more information, see Note 21.

### 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 March 31,			
	2007		2006	
	<i>(In millions)</i>			
Other:				
Operating revenues	\$	2.4	\$	1.8
Operation and maintenance		1.9		1.3
Depreciation, depletion and amortization		.3		.2



Intersegment transactions:				
Operating revenues	\$	94.1	\$	108.0
Purchased natural gas sold		87.3		101.2
Operation and maintenance		6.8		6.8

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 changes in revenues and earnings, will in fact be achieved. Please refer to assumptions contained in this section as well as the various important factors listed in Part II, Item 1A - Risk Factors, as well as Part I, Item 1A - Risk Factors in the 2006 Annual Report. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's targeted growth, revenue and earnings projections.

### MDU Resources Group, Inc.

The information noted below excludes any possible gain from the previously announced potential sale of independent power production assets.

- Earnings per common share for 2007, diluted, are projected in the range of \$1.55 to \$1.75, an increase from prior guidance of \$1.50 to \$1.70.
- The Company expects the percentage of 2007 earnings per common share, diluted, by quarter to be in the following approximate ranges:
  - o Second quarter - 25 percent to 30 percent
  - o Third quarter - 30 percent to 35 percent
  - o Fourth quarter - 25 percent to 30 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. This will add to base-load capacity and rate base. New generation is projected to be on line in late 2011 or early 2012. A major commitment decision on the project will be made in late 2007. A filing in North Dakota for prudence approval of the potential 600-MW Big Stone II generation project was made in November 2006. The Company would own approximately 116 MW of the Big Stone II project.
- In addition, the Company has entered into a contract to build 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.

### Natural gas distribution

- As discussed in Note 20, the Company has entered into a definitive merger agreement to acquire Cascade. When the acquisition is completed, it is expected to significantly enhance regulated earnings and cash flows.

### 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 March 31, 2007, was approximately \$747 million, including an acquisition, compared to \$439 million at March 31, 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 and is dependent upon the timing of receipt of necessary regulatory approvals. Through additional compression, the pipeline capacity could ultimately reach 200,000 Mcf per day.

- In 2007, total gathering and transportation throughput is expected to be consistent with 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 that range.

- The Company expects to drill between 300 and 350 wells in 2007, dependent on the timely receipt of regulatory approvals. 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 May through December 2007 as follows:

<b>Index*</b>	<b>Price Per Mcf</b>
Ventura	\$6.25 to \$6.75
NYMEX	\$6.75 to \$7.25
CIG	\$5.25 to \$5.75

\* 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 April through December 2007 in the range of \$58 to \$63 per barrel.
- The Company has hedged approximately 30 percent to 35 percent of its estimated natural gas production for the last nine months of 2007. For 2008, the Company has hedged approximately 15 percent to 20 percent of its estimated natural gas production. The hedges that are in place as of May 4, 2007, are summarized in the following chart:

<b>Commodity</b>	<b>Index*</b>	<b>Period Outstanding</b>	<b>Forward Notional Volume (MMBtu)</b>	<b>Price Swap or Costless Collar Floor-Ceiling (Per MMBtu)</b>
Natural Gas	Ventura	4/07 - 12/07	1,375,000	\$8.00-\$11.91
Natural Gas	Ventura	4/07 - 12/07	687,500	\$8.00-\$11.80
Natural Gas	Ventura	4/07 - 12/07	687,500	\$8.00-\$11.75
Natural Gas	Ventura	4/07 - 12/07	1,375,000	\$7.50-\$10.55
Natural Gas	CIG	4/07 - 12/07	1,375,000	\$7.40
Natural Gas	CIG	4/07 - 12/07	1,375,000	\$7.405
Natural Gas	Ventura	4/07 - 12/07	1,100,000	\$8.25-\$10.80
Natural Gas	CIG	4/07 - 12/07	687,500	\$7.50-\$9.12

Natural Gas	Ventura	4/07 - 12/07	1,375,000	\$8.29
Natural Gas	Ventura	4/07 - 12/07	1,375,000	\$7.85-\$9.70
Natural Gas	Ventura	4/07 - 12/07	2,750,000	\$7.67
Natural Gas	Ventura	4/07 - 10/07	1,605,000	\$7.16
Natural Gas	NYMEX	4/07 - 12/07	1,375,000	\$7.50-\$8.50
Natural Gas	Ventura	11/07 - 3/08	1,520,000	\$8.00-\$8.75
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	11/08 - 12/08	610,000	\$8.85

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

CIG is an index pricing point related to Colorado Interstate Gas Co.'s system.

### Construction materials and mining

- The Company anticipates higher average margins in 2007 as compared to 2006.
- Work backlog as of March 31, 2007, of approximately \$586 million includes a higher expected average margin than the backlog of \$610 million at March 31, 2006.

### Independent power production

- For information regarding the pending sale of the domestic independent power production assets, see Note 21.

### 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 three months of 2007 decreased \$25.7 million from the comparable 2006 period, the result of increased working capital requirements of \$51.4 million, largely due to the effects of:

- Lower natural gas costs and the timing of natural gas costs recoverable through rate adjustments at the natural gas distribution business
  - Lower natural gas prices at the natural gas and oil production business

Partially offsetting the decrease were higher depreciation, depletion and amortization expense of \$8.8 million and higher deferred income taxes of \$7.8 million.

**Investing activities** Cash flows used in investing activities in the first three months of 2007 decreased \$27.9 million compared to the comparable 2006 period, the result of:

- Lower investments of \$21.5 million, primarily the result of the sale of the Trinity Generating Facility during the first quarter of 2007
- Decreased cash used in investing activities from discontinued operations of \$20.4 million, primarily the result of lower capital expenditures related to the Hardin Generating Facility

Partially offsetting this decrease were increased net capital expenditures of \$14.1 million, primarily at the natural gas and oil production and electric businesses.

**Financing activities** Cash flows used by financing activities in the first three months of 2007 increased \$26.2 million from the comparable period in 2006, primarily the result of a decrease in the issuance of long-term debt of \$104.2 million, partially offset by a decrease in the repayment of long-term debt of \$66.7 million and an increase in the issuance of common stock of \$12.2 million.

#### **Defined benefit pension plans**

There are 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 three months of 2007 were \$126.1 million and are estimated to be approximately \$1.07 billion for 2007. With the exception of the anticipated acquisition of Cascade, the estimated 2007 capital expenditures exclude potential future acquisitions, proceeds related to the disposal of unidentified assets and potential proceeds related to the sale of domestic independent power production assets. Estimated capital expenditures include those for:

- 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
  - Anticipated acquisition of Cascade
  - Other growth opportunities

Approximately 45 percent of estimated 2007 net capital expenditures are associated with the anticipated 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; commercial paper credit facilities at Centennial and MDU Resources Group, Inc., 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 March 31, 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 and upon regulatory approval, up to a maximum of \$150 million). There were no amounts outstanding under the credit agreement at March 31, 2007. The credit agreement supports the Company's \$100 million commercial paper program. Under the Company's commercial paper program, \$1.9 million was outstanding at March 31, 2007. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires in June 2011).

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

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

To the extent short-term financing is needed for the Cascade acquisition, the Company may utilize bridge financing for up to \$310 million. For more information, see Notes 20 and 21.

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of the Company's credit agreement, see Part II, Item 7, in the 2006 Annual Report. The Company was in compliance with these covenants and met the required conditions at March 31, 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.

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 March 31, 2007, the Company could have issued approximately \$470 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred dividends was 6.0 times and 6.4 times for the 12 months ended March 31, 2007 and December 31, 2006, respectively. Additionally, the Company's first mortgage bond interest coverage was 27.1 times and 26.0 times for the 12 months ended March 31, 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 March 31, 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 March 31, 2007, the Company had \$57.0 million of first mortgage bonds outstanding, \$30.0 million of which were held by the Indenture trustee for the benefit of the Senior Note holders. At such time as the aggregate principal amount of the Company's outstanding first mortgage bonds, other than those held by the Indenture trustee, is \$20 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 March 31, 2007, the only such debt outstanding under the Indenture was \$30.0 million in aggregate principal amount of the Company's 5.98% Senior Notes due in 2033).

On July 27, 2006, the Company entered into a Sales Agency Financing Agreement 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 June 30, 2007. The Company is considering extending the Sales Agency Financing Agreement. 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 July 27, 2006, 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 March 31, 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 March 31, 2007. Under the Centennial commercial paper program, \$105.8 million was outstanding at March 31, 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 (previously \$20 million), and may be terminated by the bank at any time. As of March 31, 2007, \$42.5 million of letters of credit were outstanding, as discussed in Note 19, of which \$28.4 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, \$538.5 million was outstanding at March 31, 2007. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009. To meet potential future financing needs, Centennial may pursue other financing arrangements, including private and/or public financing.

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

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

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 March 31, 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 March 31, 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 March 31, 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. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging from approximately two 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.

#### **Contractual obligations and commercial commitments**

There are 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 March 31, 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 hedge agreements entered into by Fidelity as of March 31, 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	\$ 7.59	8,480	\$ 5,947
Natural gas swap agreements maturing in 2008	\$ 7.45	1,070	\$ (415)

  

	Weighted Average Floor/Ceiling Price (Per MMBtu)	Forward Notional Volume (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2007	\$ 7.82/\$10.31	9,273	\$ 5,644
Natural gas collar agreements maturing in 2008	\$ 7.24/\$8.27	7,620	\$ (4,165)

#### **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 March 31, 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 March 31, 2007 and 2006, and December 31, 2006, the Company had no outstanding foreign currency hedges.

### **ITEM 4. CONTROLS AND PROCEDURES**

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

#### **Evaluation of disclosure controls and procedures**

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

#### **Changes in internal controls**



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

## **PART II -- OTHER INFORMATION**

### **ITEM 1. LEGAL PROCEEDINGS**

For information regarding legal proceedings, see Note 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 risk associated with the pending sale of the domestic independent power production assets, as discussed below. These factors and the other matters discussed herein 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.

**Other Risks**

*The Company's pending sale of the domestic independent power production assets may be delayed or may not occur if certain conditions are not satisfied.*

The completion of the pending sale is subject to the fulfillment of regulatory approvals and closing conditions. The inability to complete the sale in a timely manner could affect the Company's options for funding the Cascade acquisition, and could result in the Company having to incur additional indebtedness and financing costs.

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

Between January 1, 2007 and March 31, 2007, the Company issued 83,097 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)
January 1 through January 31, 2007				
February 1 through February 28, 2007	77,834	\$26.08		
March 1 through March 31, 2007				
Total	77,834			

(1) Represents shares of common stock withheld by the Company to pay taxes in connection with the vesting of shares granted pursuant to a compensation plan.

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

**ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS**

The Company's Annual Meeting of Stockholders was held on April 24, 2007. Five proposals were submitted to stockholders as described in the Company's Proxy Statement dated March 8, 2007, and were voted upon and approved by stockholders at the meeting. The table below briefly describes the proposals and the results of the stockholder

votes.

	Shares For	Shares Against or Withheld	Abstentions	Broker Non-Votes
Proposal to elect four directors: For terms expiring in 2010 --				
Terry D. Hildestad	162,206,699	1,678,213	---	---
Dennis W. Johnson	161,958,358	1,926,554	---	---
John L. Olson	160,627,881	3,257,031	---	---
John K. Wilson	162,181,991	1,702,921	---	---
Proposal to increase the authorized shares of common stock	147,112,808	15,757,319	1,014,785	---
Proposal to declassify the board of directors	159,184,819	3,278,410	1,421,683	---
Proposal to ratify the appointment of Deloitte & Touche LLP as the Company's independent auditors for 2007	162,102,994	1,032,520	749,398	---
Shareholder proposal requesting a sustainability report	40,135,023	75,528,517	11,998,709	36,229,708

**ITEM 6. EXHIBITS**

- 3 Certificate of Amendment, dated April 24, 2007, of Restated Certificate of Incorporation of the Company
- 10(a) Centennial Power, Inc. and Colorado Energy Management, LLC Purchase and Sale Agreement by and between Centennial Energy Resources LLC, as Seller, and Montana Acquisition Company LLC, as Buyer, dated April 25, 2007
- +10(b) MDU Resources Group, Inc. Executive Incentive Compensation Plan and Rules and Regulations, as amended February 14, 2007
- +10(c) Montana-Dakota Utilities Co. Executive Incentive Compensation Plan and Rules and Regulations as amended February 14, 2007
- +10(d) WBI Holdings, Inc. Executive Incentive Compensation Plan and Rules and Regulations, as amended February 26, 2007
- +10(e) Knife River Corporation Executive Incentive Compensation Plan and Rules and Regulations, as amended February 26, 2007
- +10(f) MDU Construction Services Group, Inc. Executive Incentive Compensation Plan and Rules and Regulations, as adopted May 2, 2006
- 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.

### 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: May 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

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+10(b)

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MDU Resources Group, Inc. Executive Incentive Compensation Plan and Rules and Regulations, as amended February 14, 2007

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