MDU RESOURCES GROUP INC
Form 10-Q
August 07, 2009

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

FORM 10-Q

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

For The Quarterly Period Ended June 30, 2009

OR

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

For the Transition Period from _____________ to ______________

Commission file number 1-3480

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting company)

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 July 31, 2009: 184,073,788 shares.

DEFINITIONS

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

Abbreviation or Acronym	
2008 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2008
ALJ	Administrative Law Judge
Anadarko	Anadarko Petroleum Corporation
APB	Accounting Principles Board
APB Opinion No. 28	Interim Financial Reporting
Bbl	Barrel of oil or other liquid hydrocarbons
Bcf	Billion cubic feet
BER	Montana Board of Environmental Review
Big Stone Station	450-MW coal-fired electric generating facility located near Big Stone City, South Dakota (22.7 percent ownership)
Big Stone Station II	Proposed coal-fired electric generating facility located near Big Stone City, South Dakota (the Company anticipates ownership of at least 116 MW)
Brazilian Transmission Lines	Centennial Resources’ equity method investment in companies owning ECTE, ENTE and ERTE
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CBNG	Coalbed natural gas
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial International	Centennial Energy Resources International, Inc., a direct wholly owned subsidiary of Centennial Resources
Centennial 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
Company	MDU Resources Group, Inc.
D.C. Appeals Court	U.S. Court of Appeals for the District of Columbia Circuit
dk	Decatherm
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
FSP	FASB Staff Position
FIN	FASB Interpretation No.
FIN 46(R)	Consolidation of Variable Interest Entities (revised December 2003)
FSP FAS No. 107-1	Interim Disclosures about Fair Value of Financial Instruments
FSP FAS No. 115-2	Recognition and Presentation of Other-Than-Temporary Impairments
FSP FAS No. 132(R)-1	Employers' Disclosures about Postretirement Benefit Plan Assets
FSP FAS No. 141(R)-1	Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies
FSP FAS No. 157-2	Effective Date of FASB Statement No. 157
FSP FAS No. 157-4	Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
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
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital (effective October 1, 2008)
IPUC	Idaho Public Utilities Commission
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
kWh	Kilowatt-hour
LTM	LTM, Inc., an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MBbls	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

MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million decatherms
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana State Department of Environmental Quality
Montana Federal District Court	U.S. District Court for the District of Montana
Montana State District Court	Montana Twenty-Second Judicial District Court, Big Horn County
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
NDPSC	North Dakota Public Service Commission
Ninth Circuit	U.S. Ninth Circuit Court of Appeals
North Dakota District Court	North Dakota South Central Judicial District Court for Burleigh County
NPRC	Northern Plains Resource Council
NSPS	New Source Performance Standards
OPUC	Oregon Public Utilities Commission
Order on Rehearing	Order on Rehearing and Compliance and Remanding Certain Issues for Hearing
Oregon DEQ	Oregon State Department of Environmental Quality
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
PRP	Potentially Responsible Party
PSD	Prevention of Significant Deterioration
ROD	Record of Decision
SEC	U.S. Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
SFAS	Statement of Financial Accounting Standards
SFAS No. 71	Accounting for the Effects of Certain Types of Regulation
SFAS No. 115	Accounting for Certain Investments in Debt and Equity Securities
SFAS No. 141 (revised)	Business Combinations (revised 2007)
SFAS No. 157	Fair Value Measurements
SFAS No. 159	The Fair Value Option for Financial Assets and Financial Liabilities
SFAS No. 160	Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51 (Consolidated Financial Statements)
SFAS No. 161	Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133
SFAS No. 165	Subsequent Events

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SFAS No. 167	Amendments to FIN 46(R)
SFAS No. 168	The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162
South Dakota Federal District Court	U.S. District Court for the District of South Dakota
South Dakota SIP	South Dakota 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
WUTC	Washington Utilities and Transportation Commission
WYPSC	Wyoming Public Service Commission

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. Cascade distributes natural gas in Washington and Oregon. Intermountain distributes natural gas in Idaho. 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 contracting segment), MDU Construction Services (construction services segment), Centennial Resources and Centennial Capital (both reflected in the Other category). For more information on the Company’s business segments, see Note 15.

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PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

MDU RESOURCES GROUP, INC.

CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$263,617	$376,324	$858,191	$893,586
Construction services, natural gas and oil production, construction materials and contracting, and other	694,423	875,448	1,193,854	1,480,093
Total operating revenues	958,040	1,251,772	2,052,045	2,373,679
Operating expenses:				
Fuel and purchased power	15,166	15,718	33,896	34,495
Purchased natural gas sold	106,401	145,060	462,897	421,684
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	62,581	61,828	133,932	121,390
Construction services, natural gas and oil production, construction materials and contracting, and other	554,556	687,479	976,706	1,185,097
Depreciation, depletion and amortization	80,449	89,678	173,694	176,909
Taxes, other than income	38,822	53,518	91,774	108,041
Write-down of natural gas and oil properties	---	---	620,000	---
Total operating expenses	857,975	1,053,281	2,492,899	2,047,616
Operating income (loss)	100,065	198,491	(440,854)	326,063
Earnings from equity method investments	2,078	2,039	3,864	3,864
Other income (expense)	2,435	(37)	4,154	1,528
Interest expense	20,759	19,186	41,755	37,842
Income (loss) before income taxes	83,819	181,307	(474,591)	293,613
Income taxes	28,508	65,800	(186,100)	107,055
Net income (loss)	55,311	115,507	(288,491)	186,558
Dividends on preferred stocks	171	171	343	343
Earnings (loss) on common stock	$55,140	$115,336	$(288,834)	$186,215
Earnings (loss) per common share -- basic	$.30	$.63	$(1.57)	$1.02

Earnings (loss) per common share -- diluted	$.30	$.63	$(1.57)	$1.01
Dividends per common share	$.1550	$.1450	$.3100	$.2900
Weighted average common shares outstanding -- basic	183,964	182,972	183,876	182,785
Weighted average common shares outstanding -- diluted	184,398	183,727	183,876	183,513

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

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

	June 30, 2009	June 30, 2008	December 31, 2008
	(In thousands, except shares and per share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$34,310	$82,039	$51,714
Receivables, net	559,842	769,379	707,109
Inventories	285,814	267,125	261,524
Deferred income taxes	2,490	47,442	---
Short-term investments	1,967	13,768	2,467
Commodity derivative instruments	62,048	64,193	78,164
Prepayments and other current assets	117,381	111,100	171,314
Total current assets	1,063,852	1,355,046	1,272,292
Investments	125,361	121,279	114,290
Property, plant and equipment	6,651,088	6,507,164	7,062,237
Less accumulated depreciation, depletion and amortization	2,906,824	2,408,093	2,761,319
Net property, plant and equipment	3,744,264	4,099,071	4,300,918
Deferred charges and other assets:			
Goodwill	622,131	437,832	615,735
Other intangible assets, net	25,320	32,485	28,392
Other	242,436	166,019	256,218
Total deferred charges and other assets	889,887	636,336	900,345
Total assets	$5,823,364	$6,211,732	$6,587,845
LIABILITIES AND STOCKHOLDERS’ EQUITY			
Current liabilities:			
Short-term borrowings	$---	$79,960	$105,100
Long-term debt due within one year	27,879	87,366	78,666
Accounts payable	332,957	396,715	432,358
Taxes payable	42,151	46,200	49,784
Deferred income taxes	---	---	20,344
Dividends payable	28,686	26,723	28,640
Accrued compensation	44,141	55,631	55,646
Commodity derivative instruments	57,139	98,631	56,529

Other accrued liabilities	158,661	196,522	140,408
Total current liabilities	691,614	987,748	967,475
Long-term debt	1,636,592	1,474,908	1,568,636
Deferred credits and other liabilities:			
Deferred income taxes	540,952	685,480	727,857
Other liabilities	544,104	472,989	562,801
Total deferred credits and other liabilities	1,085,056	1,158,469	1,290,658
Commitments and contingencies			
Stockholders' equity:			
Preferred stocks	15,000	15,000	15,000
Common stockholders' equity:			
Common stock			
Shares issued -- $1.00 par value, 184,508,109 at June 30, 2009, 183,706,236 at June 30, 2008 and 184,208,283 at December 31, 2008	184,508	183,706	184,208
Other paid-in capital	941,773	925,784	938,299
Retained earnings	1,270,778	1,567,035	1,616,830
Accumulated other comprehensive income (loss)	1,669	(97,292)	10,365
Treasury stock at cost – 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,395,102	2,575,607	2,746,076
Total stockholders' equity	2,410,102	2,590,607	2,761,076
Total liabilities and stockholders' equity	$5,823,364	$6,211,732	$6,587,845

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

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

	Six Months Ended June 30, 2009	2008
	(In thousands)	
Operating activities:		
Net income (loss)	$(288,491)	$186,558
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	173,694	176,909
Earnings, net of distributions, from equity method investments	(1,685)	(1,844)
Deferred income taxes	(206,955)	34,870
Write-down of natural gas and oil properties	620,000	---
Changes in current assets and liabilities, net of acquisitions:		
Receivables	149,782	(46,550)
Inventories	(26,574)	(36,482)
Other current assets	47,837	(111,199)
Accounts payable	(66,260)	18,953
Other current liabilities	2,218	11,209
Other noncurrent changes	(5,141)	6,381
Net cash provided by operating activities	398,425	238,805
Investing activities:		
Capital expenditures	(272,867)	(386,014)
Acquisitions, net of cash acquired	(3,764)	(271,191)
Net proceeds from sale or disposition of property	7,494	26,379
Investments	(2,368)	80,389
Net cash used in investing activities	(271,505)	(550,437)
Financing activities:		
Issuance of short-term borrowings	---	79,960
Repayment of short-term borrowings	(105,100)	(1,700)
Issuance of long-term debt	109,400	379,644
Repayment of long-term debt	(92,024)	(125,637)
Proceeds from issuance of common stock	284	4,945
Dividends paid	(57,325)	(53,296)
Tax benefit on stock-based compensation	144	3,737
Net cash provided by (used in) financing activities	(144,621)	287,653
Effect of exchange rate changes on cash and cash equivalents	297	198
Decrease in cash and cash equivalents	(17,404)	(23,781)
Cash and cash equivalents -- beginning of year	51,714	105,820
Cash and cash equivalents -- end of period	$34,310	$82,039

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

June 30, 2009 and 2008
(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 2008 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 2008 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 and are of a normal recurring nature. Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

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. Allowance for doubtful accounts

The Company's allowance for doubtful accounts as of June 30, 2009 and 2008, and December 31, 2008, was $16.5 million, $14.3 million and $13.7 million, respectively.

4. Natural gas in storage

Natural gas in storage for the Company's regulated operations is generally carried at cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories and was $19.1 million, $11.4 million and $27.6 million at June 30, 2009 and 2008, and December 31, 2008, respectively. The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $40.3 million, $43.0 million, and $43.4 million at June 30, 2009 and 2008, and December 31, 2008, respectively.

5. Inventories

Inventories, other than natural gas in storage for the Company’s regulated operations, consisted primarily of aggregates held for resale of $96.3 million, $110.2 million and $89.1 million; materials and supplies of $69.4 million, $60.5 million and $70.3 million; asphalt oil of $49.8 million, $41.2 million and $22.1 million; and other inventories of $51.2 million, $43.8 million and $52.4 million, as of June 30, 2009 and 2008, and December 31, 2008, respectively. These inventories were stated at the lower of average cost or market value.

6. Natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a “ceiling test” that limits such costs to the aggregate of the present value of future net cash flows from proved reserves based on spot market prices that exist at the end of the period discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties less applicable income taxes. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

Due to low natural gas and oil prices that existed on March 31, 2009, the Company’s capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2009. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-down amounted to $620.0 million ($384.4 million after tax) for the three months ended March 31, 2009. At June 30, 2009, the Company’s full-cost ceiling exceeded the Company’s capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to June 30, 2009, could result in future write-downs of the Company’s natural gas and oil properties.

The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized an additional write-down of its natural gas and oil properties of $107.9 million ($66.9 million after tax) as of March 31, 2009, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company’s cash flow hedges, see Note 13.

7. Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) 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 June 30, 2009 and 2008, and the six months ended June 30, 2008, there were no shares excluded from the calculation of diluted earnings per share. Diluted loss per common share for the six months ended June 30, 2009, was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the applicable period. Due to the loss on common stock for the six months ended June 30, 2009, the effect of outstanding stock options, restricted stock grants and performance share awards was excluded from the computation of diluted loss per common share as their effect was antidilutive. Common stock outstanding includes issued shares less shares held in treasury.

8. Cash flow information

Cash expenditures for interest and income taxes were as follows:

	Six Months Ended June 30, 2009	2008
	(In thousands)	
Interest, net of amount capitalized	$ 40,588	$ 37,504
Income taxes	$ 13,343	$ 91,398

9. New accounting standards

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 was effective for the Company on January 1, 2008. FSP FAS No. 157-2 delayed the effective date of SFAS No. 157 for certain nonfinancial assets and nonfinancial liabilities to January 1, 2009. The types of assets and liabilities that are recognized at fair value under the provisions of SFAS No. 157 effective January 1, 2009, due to the delayed effective date, include nonfinancial assets and nonfinancial liabilities initially measured at fair value in a business combination or new basis event, certain fair value measurements associated with goodwill impairment testing, indefinite-lived intangible assets and nonfinancial long-lived assets measured at fair value for impairment assessment, and asset retirement obligations initially measured at fair value. The adoption of SFAS No. 157, including the application to certain nonfinancial assets and nonfinancial liabilities with a delayed effective date of January 1, 2009, did not have a material effect on the Company's financial position or results of operations.

SFAS No. 141 (revised) In December 2007, the FASB issued SFAS No. 141 (revised). SFAS No. 141 (revised) requires an acquirer to recognize and measure the assets acquired, liabilities assumed and any noncontrolling interests in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exception. In addition, SFAS No. 141 (revised) requires that acquisition-related costs will be generally expensed as incurred. SFAS No. 141 (revised) also expands the disclosure requirements for business combinations. SFAS No. 141 (revised) was effective for the Company on January 1, 2009. The adoption of SFAS No. 141 (revised) did not have a material effect on the Company’s financial position or results of operations.

SFAS No. 160 In December 2007, the FASB issued SFAS No. 160. SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 was effective for the Company on January 1, 2009. The adoption of SFAS No. 160 did not have a material effect on the Company’s financial position or results of operations.

SFAS No. 161 In March 2008, the FASB issued SFAS No. 161. SFAS No. 161 requires enhanced disclosures about an entity’s derivative and hedging activities including how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for, and how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. This Statement was effective for the Company on January 1, 2009. The adoption of SFAS No. 161 requires additional disclosures regarding the Company’s derivative instruments; however, it did not impact the Company’s financial position or results of operations.

FSP FAS No. 132(R)-1 In December 2008, the FASB issued FSP FAS No. 132(R)-1. FSP FAS No. 132(R)-1 provides guidance on an employer’s disclosures about plan assets of a defined benefit pension or other postretirement plan to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period and significant concentrations of risk within plan assets. This statement was effective for the Company on January 1, 2009. The adoption of FSP FAS No. 132(R)-1 will require additional disclosures regarding the Company's defined benefit pension and other postretirement plans in the annual financial statements; however, it will not impact the Company's financial position or results of operations.

Modernization of Oil and Gas Reporting In January 2009, the SEC adopted final rules amending its oil and gas reporting requirements. The new rules include changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves and permitting disclosure of probable and possible reserves. The final rules will be effective on December 31, 2009.

FSP FAS No. 107-1 In April 2009, the FASB issued FSP FAS No. 107-1. FSP FAS No. 107-1 requires disclosures about the fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This statement was effective for the Company in the second quarter of 2009. The adoption of FSP FAS No. 107-1 requires additional disclosures regarding the Company’s fair value of financial instruments; however, it did not impact the Company’s financial position or results of operations.

FSP FAS No. 115-2 In April 2009, the FASB issued FSP FAS No. 115-2. FSP FAS No. 115-2 amends the other-than-temporary impairment guidance for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. This statement was effective for the Company in the second quarter of 2009. The adoption of FSP FAS No. 115-2 did not have a material effect on the Company’s financial position or results of operations.

FSP FAS No. 157-4 In April 2009, the FASB issued FSP FAS No. 157-4. FSP FAS No. 157-4 provides additional guidance for estimating fair value in accordance with SFAS No. 157, when the volume and level of activity for the asset or liability have significantly decreased. This statement was effective for the Company in the second quarter of 2009. The adoption of FSP FAS No. 157-4 did not have a material effect on the Company’s financial position or results of operations.

FSP FAS No. 141(R)-1 In April 2009, the FASB issued FSP FAS No. 141(R)-1. FSP FAS No. 141(R)-1 amends and clarifies SFAS No. 141 (revised), to address application issues raised in regard to initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This statement was effective for the Company on January 1, 2009. The adoption of FSP FAS No. 141(R)-1 did not have a material effect on the Company's financial position or results of operations.

SFAS No. 165 In May 2009, the FASB issued SFAS No. 165. SFAS No. 165 establishes standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In addition it requires the disclosure of the date through which the Company has evaluated subsequent events and whether it represents the date the financial statements were issued or were available to be issued. SFAS No. 165 was effective for the Company on June 30, 2009. The adoption of SFAS No. 165 did not have a material effect on the Company’s financial position or results of operations.

SFAS No. 167 In June 2009, the FASB issued SFAS No. 167. SFAS No. 167 amends certain requirements of FIN 46(R). SFAS No. 167 changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting rights should be consolidated and modifies the approach for determining the primary beneficiary of a variable interest entity. SFAS No. 167 will require a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. SFAS No. 167 will be effective for the Company on January 1, 2010. The Company is evaluating the effects of the adoption of SFAS No. 167.

SFAS No. 168 In June 2009, the FASB issued SFAS No. 168. SFAS No. 168 establishes the FASB Accounting Standards Codification as the source of authoritative generally accepted accounting principles recognized by the FASB. The FASB Accounting Standards Codification is a reorganization of current GAAP into a topical format. It will be effective for the Company in the third quarter of 2009. The adoption of SFAS No. 168 will require the Company to revise its disclosures when referencing generally accepted accounting principles.

10. Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive loss resulted from losses on derivative instruments qualifying as hedges and foreign currency translation adjustments. For more information on derivative instruments, see Note 13.

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

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008
	(In thousands)	
Net income	$ 55,311	$ 115,507
Other comprehensive loss:		
Net unrealized loss on derivative instruments qualifying as hedges:		
Net unrealized loss on derivative instruments arising during the period, net of tax of $(4,028) and $(37,169) in 2009 and 2008, respectively	(6,571)	(60,644)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $11,415 and $(5,045) in 2009 and 2008, respectively	18,625	(8,230)
Net unrealized loss on derivative instruments qualifying as hedges	(25,196)	(52,414)
Foreign currency translation adjustment, net of tax of $3,711 and $2,570 in 2009 and 2008, respectively	5,756	3,977
	(19,440)	(48,437)
Comprehensive income	$ 35,871	$ 67,070

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands)	
Net income (loss)	$ (288,491)	$ 186,558
Other comprehensive loss:		
Net unrealized loss on derivative instruments qualifying as hedges:		
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $5,634 and $(53,537) in 2009 and 2008, respectively	9,193	(87,433)
Less: Reclassification adjustment for gain on derivative instruments included in net income, net of tax of $14,646 and $2,786 in 2009 and 2008, respectively	23,896	4,522
Net unrealized loss on derivative instruments qualifying as hedges	(14,703)	(91,955)
Foreign currency translation adjustment, net of tax of $3,875 and $2,876 in 2009 and 2008, respectively	6,007	4,461
	(8,696)	(87,494)
Comprehensive income (loss)	$ (297,187)	$ 99,064

11. Equity method investments

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at June 30, 2009, include the Brazilian Transmission Lines.

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

At June 30, 2009 and 2008, and December 31, 2008, the Company's equity method investments had total assets of $348.3 million, $431.1 million and $294.7 million, respectively, and long-term debt of $171.7 million, $218.8 million and $158.0 million, respectively. The Company's investment in its equity method investments was approximately $52.6 million, $63.0 million and $44.4 million, including undistributed earnings of $8.4 million, $8.7 million and $6.8 million, at June 30, 2009 and 2008, and December 31, 2008, respectively.

12. Goodwill and other intangible assets

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

Six Months Ended June 30, 2009	Balance as of January 1, 2009	Goodwill Acquired During the Year* (In thousands)	Balance as of June 30, 2009
Electric	$ ---	$ ---	$ ---
Natural gas distribution	344,952	296	345,248
Construction services	95,619	4,398	100,017
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and contracting	174,005	1,702	175,707
Other	---	---	---
Total	$ 615,735	$ 6,396	$ 622,131

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

Six Months Ended June 30, 2008	Balance as of January 1, 2008	Goodwill Acquired During the Year* (In thousands)	Balance as of June 30, 2008
Electric	$ ---	$ ---	$ ---
Natural gas distribution	171,129	(11)	171,118
Construction services	91,385	3,937	95,322
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and contracting	162,025	8,208	170,233
Other	---	---	---
Total	$ 425,698	$ 12,134	$ 437,832

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

Year Ended December 31, 2008	Balance as of January 1, 2008	Goodwill Acquired During the Year* (In thousands)	Balance as of December 31, 2008
Electric	$ ---	$ ---	$ ---
Natural gas distribution	171,129	173,823	344,952
Construction services	91,385	4,234	95,619
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and contracting	162,025	11,980	174,005
Other	---	---	---
Total	$ 425,698	$ 190,037	$ 615,735

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

Other intangible assets were as follows:

	June 30, 2009	June 30, 2008 (In thousands)	December 31, 2008
Customer relationships	$ 21,688	$ 25,262	$ 21,842
Accumulated amortization	(8,142)	(5,979)	(6,985)
	13,546	19,283	14,857
Noncompete agreements	9,792	10,823	10,080
Accumulated amortization	(5,942)	(4,493)	(5,126)
	3,850	6,330	4,954
Other	10,679	8,370	10,949
Accumulated amortization	(2,755)	(1,498)	(2,368)
	7,924	6,872	8,581
Total	$ 25,320	$ 32,485	$ 28,392

Amortization expense for amortizable intangible assets for the three and six months ended June 30, 2009, was $1.2 million and $2.6 million, respectively. Amortization expense for the three and six months ended June 30, 2008, was $1.2 million and $2.6 million, respectively. Estimated amortization expense for amortizable intangible assets is $4.8 million in 2009, $3.9 million in 2010, $3.1 million in 2011, $3.0 million in 2012, $2.6 million in 2013 and $10.5 million thereafter.

13. Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. As of June 30, 2009, 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 2008 Annual Report.

Cascade and Intermountain

At June 30, 2009, Cascade and Intermountain held natural gas swap agreements, with total forward notional volumes of 33.8 million MMBtu, which were not designated as hedges. Cascade and Intermountain utilize natural gas swap agreements to manage a portion of their regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the IPUC, WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Cascade and Intermountain apply SFAS No. 71 and record periodic changes in the fair market value of the derivative instruments on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade and Intermountain will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the three and six months ended June 30, 2009, Cascade and Intermountain recorded the decrease in the fair market value of the derivative instruments of $28.8 million and $22.0 million, respectively, in regulatory assets.

Certain of Cascade's derivative instruments contain credit-risk-related contingent features that permit the counterparties to require collateralization if Cascade's derivative liability positions exceed certain dollar thresholds. The dollar thresholds in certain of Cascade's agreements are determined and may fluctuate based on Cascade's credit rating on its debt. In addition, Cascade's and Intermountain's derivative instruments contain cross-default provisions that state if the entity fails to make payment with respect to certain of its indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of such entity's derivative instruments in liability positions. The aggregate fair value of Cascade and Intermountain's derivative instruments with credit-risk-related contingent features that are in a liability position at June 30, 2009, was $67.9 million. Cascade has posted collateral of $8.5 million associated with certain of these contracts. The aggregate fair value of additional assets that would have been required to be posted as collateral and the fair value of assets that would have been needed to settle the instruments immediately if the credit-risk related contingent features were triggered on June 30, 2009, was $59.4 million.

Fidelity

At June 30, 2009, Fidelity held natural gas swaps, basis swaps and collar agreements with total forward notional volumes of 28.7 million MMBtu, and oil swaps and collar agreements with total forward notional volumes of 1.2 million Bbl, which were designated as cash flow hedging instruments. At June 30, 2009, Fidelity held natural gas basis swaps with total forward notional volumes of 6.4 million MMBtu, which did not qualify for hedge accounting. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on its forecasted sales of natural gas and oil production.

The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or 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 and oil quantities are settled, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings. The proceeds received for natural gas and oil production are generally based on market prices.

Excluding the natural gas basis swaps which were not designated as hedges, the amount of hedge ineffectiveness was immaterial for the three and six months ended June 30, 2009, and there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges. The loss on the derivative instruments that did not qualify for hedge accounting was reported in operating revenues on the Consolidated Statements of Income and was immaterial for the three and six months ended June 30, 2009.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in operating revenues on the Consolidated Statements of Income. For further information regarding the gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in other comprehensive income and the gains and losses reclassified from accumulated other comprehensive income into earnings, see Note 10.

As of June 30, 2009, the maximum term of the swap and collar agreements, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 30 months. The Company estimates that over the next 12 months net gains of approximately $33.2 million (after tax) will be reclassified from accumulated other comprehensive income into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Certain of Fidelity's derivative instruments contain cross-default provisions that state if Fidelity fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's derivative instruments with credit-risk-related contingent features that are in a liability position at June 30, 2009, was $10.1 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on June 30, 2009, was $10.1 million.

The location and fair value of all of the Company's derivative instruments in the Consolidated Balance Sheets as of June 30, 2009, were as follows:

	Asset Derivatives		Liability Derivatives	
	Location on Consolidated Balance Sheets	Fair Value	Location on Consolidated Balance Sheets	Fair Value
		(in thousands)		
Commodity derivatives designated as hedges:				
	Commodity derivative instruments	$62,047	Commodity derivative instruments	$8,440
	Other assets - noncurrent	4,217	Other liabilities – noncurrent	1,538
Total derivatives designated as hedges		66,264		9,978
Commodity derivatives not designated as hedges:				
	Commodity derivative instruments	1	Commodity derivative instruments	48,699
	Other assets - noncurrent	1	Other liabilities – noncurrent	10,786
Total derivatives not designated as hedges		2		59,485
Total derivatives		$66,266		$69,463

Note: The fair value of the commodity derivative instruments not designated as hedges is presented net of collateral provided to the counterparties by Cascade of $8.5 million.

14. Fair value measurements

The Company elected to measure its investments in certain fixed-income and equity securities at fair value in accordance with SFAS No. 159. These investments had previously been accounted for as available-for-sale investments in accordance with SFAS No. 115. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $29.5 million, $34.0 million and $27.7 million, as of June 30, 2009 and 2008, and December 31, 2008, respectively, are classified as Investments on the Consolidated Balance Sheets. The increase in the fair value of these investments for the three and six months ended June 30, 2009, was $3.7 million (before tax) and $1.8 million (before tax), respectively. The decrease in the fair value of these investments for the three and six months ended June 30, 2008, was $184,000 (before tax) and $2.3 million (before tax), respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income. The Company did not elect the fair value option for its remaining available-for-sale securities, which are auction rate securities. The Company's auction rate securities, which totaled $11.4 million at June 30, 2009 and 2008, and December 31, 2008, are accounted for as available-for-sale in accordance with SFAS No. 115 and are recorded at fair value. The fair value of the auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments.

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The statement establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The Company’s assets and liabilities measured at fair value on a recurring basis are as follows:

	Fair Value Measurements at June 30, 2009, Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Collateral Provided to Counterparties	Balance at June 30, 2009
			(In thousands)		
Assets:					
Available-for-sale securities	$29,532	$11,400	$ ---	$ ---	$40,932
Commodity derivative instruments - current	---	62,048	---	---	62,048
Commodity derivative instruments - noncurrent	---	4,218	---	---	4,218
Total assets measured at fair value	$29,532	$77,666	$ ---	$ ---	$107,198
Liabilities:					
Commodity derivative instruments - current	$---	$65,604	$ ---	$ 8,465	$57,139
Commodity derivative instruments - noncurrent	---	12,324	---	---	12,324
Total liabilities measured at fair value	$---	$77,928	$ ---	$ 8,465	$69,463

	Fair Value Measurements at June 30, 2008, Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3) (In thousands)	Collateral Provided to Counterparties	Balance at June 30, 2008
Assets:					
Available-for-sale securities	$33,990	$11,400	$ ---	$ ---	$45,390
Commodity derivative instruments - current	---	64,193	---	---	64,193
Commodity derivative instruments - noncurrent	---	24,943	---	---	24,943
Total assets measured at fair value	$33,990	$100,536	$ ---	$ ---	$134,526
Liabilities:					
Commodity derivative instruments - current	$---	$98,631	$ ---	$ ---	$98,631
Commodity derivative instruments - noncurrent	---	39,984	---	---	39,984
Total liabilities measured at fair value	$---	$138,615	$ ---	$ ---	$138,615

	Fair Value Measurements at December 31, 2008, Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3) (In thousands)	Collateral Provided to Counterparties	Balance at December 31, 2008
Assets:					
Available-for-sale securities	$27,725	$11,400	$ ---	$ ---	$ 39,125
Commodity derivative instruments - current	---	78,164	---	---	78,164
Commodity derivative instruments - noncurrent	---	3,222	---	---	3,222
Total assets measured at fair value	$27,725	$92,786	$ ---	$ ---	$ 120,511
Liabilities:					
Commodity derivative instruments - current	$---	$67,629	$ ---	$ 11,100	$ 56,529
Commodity derivative instruments - noncurrent	---	23,534	---	---	23,534
Total liabilities measured at fair value	$---	$91,163	$ ---	$ 11,100	$ 80,063

The estimated fair value of the Company’s Level 1 available-for-sale securities is based on quoted market prices in active markets for identical equity and fixed-income securities. The estimated fair value of the Company’s Level 2 available-for-sale securities is based on comparable market transactions. The estimated fair value of the Company’s commodity derivative instruments reflects the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date. These values are based upon, among other things, futures prices, volatility and time to maturity.

The Company’s long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The estimated fair value of the Company’s long-term debt was based on quoted market prices of the same or similar issues.

The estimated fair value of the Company's long-term debt at June 30 was as follows:

	2009	
	Carrying Amount	Fair Value
	(In thousands)	
Long-term debt	$ 1,664,471	$ 1,538,693

The carrying amounts of the Company’s remaining financial instruments included in current assets and current liabilities approximate their fair values.

15. 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 Centennial Resources’ equity method investment in the Brazilian Transmission Lines.

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

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire protection systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes 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. This 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 in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and contracting 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 contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

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 Other category also includes Centennial Resources' equity method investment in the Brazilian Transmission Lines.

The information below follows the same accounting policies as described in Note 1 of the Company's Notes to Consolidated Financial Statements in the 2008 Annual Report. Information on the Company's businesses was as follows:

Three Months Ended June 30, 2009	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 44,508	$ ---	$ 3,263
Natural gas distribution	164,158	---	(4,765)
Pipeline and energy services	54,951	13,046	10,876
	263,617	13,046	9,374
Construction services	220,697	10	6,931
Natural gas and oil production	84,291	20,488	20,779
Construction materials and contracting	389,435	---	15,983
Other	---	2,699	2,073
	694,423	23,197	45,766
Intersegment eliminations	---	(36,243)	---
Total	$ 958,040	$ ---	$ 55,140

Three Months Ended June 30, 2008	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 45,873	$ ---	$ 2,787
Natural gas distribution	196,956	---	5,443
Pipeline and energy services	133,495	21,621	6,842
	376,324	21,621	15,072
Construction services	324,632	38	14,089
Natural gas and oil production	123,370	91,824	71,687
Construction materials and contracting	427,446	---	12,735
Other	---	2,660	1,753
	875,448	94,522	100,264
Intersegment eliminations	---	(116,143)	---
Total	$ 1,251,772	$ ---	$ 115,336

Six Months Ended June 30, 2009	External Operating Revenues	Inter-segment Operating Revenues (In thousands)	Earnings (Loss) on Common Stock
Electric	$ 95,755	$ ---	$ 8,329
Natural gas distribution	647,313	---	19,114
Pipeline and energy services	115,123	37,973	17,261
	858,191	37,973	44,704
Construction services	465,495	41	15,565
Natural gas and oil production	155,450	55,451	(352,537)
Construction materials and contracting	572,909	---	330
Other	---	5,398	3,104
	1,193,854	60,890	(333,538)
Intersegment eliminations	---	(98,863)	---
Total	$ 2,052,045	$ ---	$ (288,834)

Six Months Ended June 30, 2008	External Operating Revenues	Inter-segment Operating Revenues (In thousands)	Earnings on Common Stock
Electric	$ 98,129	$ ---	$ 8,267
Natural gas distribution	559,101	---	21,828
Pipeline and energy services	236,356	52,553	13,996
	893,586	52,553	44,091
Construction services	632,019	82	24,903
Natural gas and oil production	219,351	165,430	122,333
Construction materials and contracting	628,723	---	(8,362)
Other	---	5,296	3,250
	1,480,093	170,808	142,124
Intersegment eliminations	---	(223,361)	---
Total	$ 2,373,679	$ ---	$ 186,215

Earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from construction services, natural gas and oil production, construction materials and contracting, and other are all from nonregulated operations.

16. Employee benefit plans

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

Three Months Ended June 30,	Pension Benefits 2009	Pension Benefits 2008	Other Postretirement Benefits 2009	Other Postretirement Benefits 2008
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 1,966	$ 2,191	$ 651	$ 660
Interest cost	5,430	6,505	1,530	1,797
Expected return on assets	(5,673)	(8,458)	(1,544)	(1,691)
Amortization of prior service cost (credit)	151	198	(810)	(988)
Amortization net actuarial loss	643	332	170	246
Amortization of net transition obligation	---	---	625	763
Net periodic benefit cost, including amount capitalized	2,517	768	622	787
Less amount capitalized	484	217	(23)	124
Net periodic benefit cost	$ 2,033	$ 551	$ 645	$ 663

Six Months Ended June 30,	Pension Benefits 2009	Pension Benefits 2008	Other Postretirement Benefits 2009	Other Postretirement Benefits 2008
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 4,063	$ 4,820	$ 1,091	$ 1,150
Interest cost	10,959	11,629	2,725	2,982
Expected return on assets	(12,530)	(14,494)	(2,817)	(3,388)
Amortization of prior service cost (credit)	302	364	(1,378)	(1,677)
Amortization net actuarial loss	817	574	355	361
Amortization of net transition obligation	---	---	1,063	1,294
Net periodic benefit cost, including amount capitalized	3,611	2,893	1,039	722
Less amount capitalized	765	396	23	189
Net periodic benefit cost	$ 2,846	$ 2,497	$ 1,016	$ 533

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 the employee’s retirement or to their beneficiaries upon death for a 15-year period. The Company's net periodic benefit cost for this plan for the three and six months ended June 30, 2009, was $2.2 million and $4.3 million, respectively. The Company's net periodic benefit cost for this plan for the three and six months ended June 30, 2008, was $2.4 million and $4.4 million, respectively.

17. Regulatory matters and revenues subject to refund

In August 2008, Montana-Dakota filed an application with the WYPSC for an electric rate increase. Montana-Dakota requested a total increase of $757,000 annually or approximately 4 percent above current rates. On April 6, 2009, Montana-Dakota and the Office of Consumer Advocate filed a Stipulation with the WYPSC, agreeing to an increase of $425,000 annually or 2.3 percent with rates effective May 1, 2009. On April 15, 2009, the WYPSC approved the Stipulation.

In November 2006, Montana-Dakota filed an application with the NDPSC requesting an advance determination of prudence of Montana-Dakota's ownership interest in Big Stone Station II. In August 2008, the NDPSC approved Montana-Dakota’s request for advance determination of prudence for ownership in the proposed Big Stone Station II for a minimum of 121.8 MW up to a maximum of 133 MW and a proportionate ownership share of the associated transmission electric resources. In September 2008, the intervenors in the proceeding appealed the NDPSC order to the North Dakota District Court. The intervenors brief was filed January 21, 2009, and Montana-Dakota filed its response brief on February 17, 2009.

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. Currently, the only remaining issue outstanding related to this rate change application is in regard to certain service restrictions. In May 2004, the FERC remanded this issue to an ALJ for resolution. In November 2005, the FERC issued an Order on Initial Decision affirming the ALJ's Initial Decision regarding certain service and annual demand quantity restrictions. In April 2006, the FERC issued an Order on Rehearing denying Williston Basin's Request for Rehearing of the FERC's Order on Initial Decision. In April 2006, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision and its Order on Rehearing. In March 2008, the D.C. Appeals Court issued its opinion in this matter concerning the service restrictions. The D.C. Appeals Court found that the FERC was correct to decide the case under the “just and reasonable” standard of section 5(a) of the Natural Gas Act; however, it remanded the case back to the FERC as flaws in the FERC’s reasoning render its orders arbitrary and capricious. In December 2008, the FERC issued its Order Requesting Data and Comment on this matter. Williston Basin and Northern States Power Company provided responses to FERC’s requests in January 2009. In addition, initial comments addressing specific issues identified by the FERC were filed on February 17, 2009, and reply comments were filed on March 9, 2009. The initial and reply comments should contain all the arguments and supporting evidence the parties determine they need to provide to update the record with regard to the issue under remand.

18. Contingencies

Litigation

Coalbed Natural Gas Operations Fidelity is a party to and/or certain of its operations are or have been the subject of more than a half dozen lawsuits in Montana and Wyoming related to administrative regulation of water produced in connection with Fidelity’s CBNG development in the Powder River Basin. These cases involve legal challenges to the issuance of discharge permits, as well as challenges to the State of Wyoming’s CBNG water permitting procedures.

In April 2006, the Northern Cheyenne Tribe filed a complaint in Montana State District Court against the Montana DEQ seeking to set aside Fidelity's renewed direct discharge and treatment permits. The Northern Cheyenne Tribe claimed the Montana DEQ violated the Clean Water Act and the Montana Water Quality Act by failing to include in the permits conditions requiring application of the best practicable control technology currently available and by failing to impose a nondegradation policy like the one the BER adopted soon after the permit was issued. In addition, the Northern Cheyenne Tribe claimed that the actions of the Montana DEQ violated the Montana State Constitution's guarantee of a clean and healthful environment, that the Montana DEQ's related environmental assessment was invalid, that the Montana DEQ was required, but failed, to prepare an EIS and that the Montana DEQ failed to consider other alternatives to the issuance of the permits. Fidelity, the NPRC and the TRWUA were granted leave to intervene in this proceeding. On January 12, 2009, the Montana State District Court decided the case in favor of Fidelity and the Montana DEQ in all respects, denying the motions of the Northern Cheyenne Tribe, TRWUA, and NPRC, and granting the cross-motions of the Montana DEQ and Fidelity in their entirety. As a result, Fidelity may continue to utilize its direct discharge and treatment permits. The NPRC, the TRWUA and the Northern Cheyenne Tribe appealed the decision to the Montana Supreme Court on March 9, 11, and 13, 2009, respectively.

Fidelity's discharge of water pursuant to its two permits is its primary means for managing CBNG-produced water. Fidelity believes that its discharge permits should, assuming normal operating conditions, allow Fidelity to continue its existing CBNG operations through the expiration of the permits in March 2011. If its permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

The Powder River Basin Resource Council funded litigation, filed in Wyoming State District Court in June 2007, on behalf of two surface owners against the Wyoming State Engineer and the Wyoming Board of Control. The plaintiffs sought a declaratory judgment that current ground water permitting practices were unlawful; that the state was required to adopt rules and procedures to ensure that coalbed groundwater was managed in accordance with the Wyoming Constitution and other laws; and that would prohibit the Wyoming State Engineer from issuing permits to produce coalbed groundwater and permits to store coalbed groundwater in reservoirs until the Wyoming State Engineer adopted such rules. The Wyoming State District Court granted the Petroleum Association of Wyoming's motion to intervene provided that the defendants motion to dismiss was denied. Fidelity partly funded the intervention. In May 2008, the Wyoming State District Court dismissed the case. The plaintiffs appealed to the Wyoming Supreme Court and on May 7, 2009, the Wyoming Supreme Court affirmed the dismissal.

Fidelity will continue to vigorously defend its interests in all CBNG-related litigation in which it is involved. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could adversely impact Fidelity's existing CBNG operations and/or the future development of this resource in the affected regions.

Electric Operations In June 2008, the Sierra Club filed a complaint in the South Dakota Federal District Court against Montana-Dakota and the two other co-owners of the Big Stone Station. The complaint alleged certain violations of the PSD and NSPS provisions of the Clean Air Act and certain violation of the South Dakota SIP. The action further alleged that the Big Stone Station was modified and operated without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleged that these actions contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought declaratory and injunctive relief to bring the co-owners of the Big Stone Station into compliance with the Clean Air Act and the South Dakota SIP and to require them to remedy the alleged violations. The Sierra Club also sought unspecified civil penalties, including a beneficial mitigation project. The Company believes the claims are without merit and that Big Stone Station has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. On March 31, 2009, the District Court granted the motion of the co-owners to dismiss the complaint. The Sierra Club filed a motion requesting the District Court to reconsider its ruling on a portion of the order dismissing the complaint which was denied on July 22, 2009. On July 30, 2009, the Sierra Club appealed from the orders dismissing the case and denying the motion for reconsideration to the United States Court of Appeals for the Eighth Circuit.

Natural Gas Storage Based on reservoir and well pressure data and other information, Williston Basin believes that reservoir pressure (and therefore the amount of gas) in the EBSR, one of its natural gas storage reservoirs, decreased as a result of Howell and Anadarko’s drilling and production activities in areas within and near the originally certificated boundaries of the EBSR. Howell and Anadarko have produced approximately 13.3 Bcf of natural gas from such production activities and as a result, Williston Basin estimates that as of June 30, 2009, between 11.5 and 12 Bcf of its storage gas had been diverted from the EBSR. Although the Howell and Anadarko wells are shut in and no longer producing, Williston Basin believes additional amounts of storage gas will likely be diverted from the EBSR (as originally certificated), with the total diverted amount approximating Howell and Anadarko’s production, as pressures in the various interconnected geologic formations equalize.

Williston Basin filed suit in Montana Federal District Court in January 2006, seeking to enjoin Howell and Anadarko’s present and future production from specified wells in and near the EBSR and to recover damages for the loss of storage gas. The Montana Federal District Court entered an Order in July 2006, dismissing the case for lack of subject matter jurisdiction. Williston Basin appealed and in May 2008, the Ninth Circuit affirmed the Montana Federal District Court’s decision. In response to the loss of gas from the drilling and production activities of Howell and Anadarko, Williston Basin installed temporary compression at the site in 2006 in order to maintain deliverability into the transmission system. Williston Basin also leased working gas for the 2007 – 2008 and 2008 – 2009 heating seasons to supplement its cushion gas. In another effort to protect the viability of the EBSR, Williston Basin, in April 2008, filed an application with the FERC to expand the boundaries of the original EBSR. The proposed expansion includes the areas from which Howell and Anadarko were producing. On April 16, 2009, the FERC approved Williston Basin’s application for an expanded EBSR.

In related litigation, Howell filed suit in Wyoming State District Court against Williston Basin in February 2006, asserting that it was entitled to produce all gas that could be drawn to its wells, including gas from the EBSR. Williston Basin counterclaimed in that lawsuit for damages caused by Howell and Anadarko's drilling activity. By an agreement effective as of July 2, 2009, the parties resolved the litigation pending before the Wyoming State District Court and Howell and Anadarko have agreed to replace a portion of the storage gas lost by Williston Basin and dismiss the suit with prejudice. Williston Basin intends to significantly reduce or eliminate any adverse effects caused by the loss through the replacement of additional amounts of cushion gas, the use of compression, or both.

Construction Materials LTM is a third-party defendant in litigation pending in Oregon Circuit Court regarding the concrete floors in an industrial food processing facility located in Jackson County, Oregon. The complaint against the facility construction contractor alleges the concrete floors of the facility are defective and must be removed and replaced for suitable repair. Damages, including disruption of the food processing operations, have been estimated by the plaintiff to be in excess of $15 million. The construction contractor's answer and third-party complaint alleges the owner and third-party defendants, including LTM which supplied the concrete, are primarily responsible for any defects in the concrete surfaces. Discovery is currently being conducted by the parties. A trial date has not been set.

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 PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by MBI from Georgia Pacific-West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. 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 and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include MBI or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. MBI also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are 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 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 limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter of March 2, 2009, LWG stated its intent to file suit against MBI and others to recover LWG's investigation costs to the extent MBI cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, MBI has agreed to participate in the alternative dispute resolution process.

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

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

The first claim is for soil and groundwater contamination at a site in Oregon and was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. An ecological risk assessment draft report was submitted to the Oregon DEQ in June 2009. The assessment showed no unacceptable risk to the aquatic ecological receptors present in the shoreline along the site and concluded that no further ecological investigation is necessary. The report is being reviewed by the Oregon DEQ. It is anticipated the Oregon DEQ will recommend a cleanup alternative for the site after it completes its review of the report. It is not known at this time what share of the cleanup costs will actually be borne by Cascade.

The second claim is for contamination at a site in Washington and was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants that will require further investigation and cleanup. A supplemental investigation is currently being conducted to better characterize the extent of the contamination. The supplemental investigation is expected to be completed in 2009. The data from the preliminary investigation indicates other current and former owners of properties and businesses in the vicinity of the site may also be responsible for the contamination. There is currently not enough information to estimate the potential liability associated with this claim.

The third claim is also for contamination at a site in Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade's predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim.

To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

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 up to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent Power LLC, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation. The guarantee, which has no fixed maximum, expires when CEM has completed its obligations under the construction contract. The warranty period associated with this project will expire one year after the date of substantial completion of construction. CEM declared substantial completion of the plant on February 16, 2009, and on February 27, 2009, Centennial received a Notice and Demand from LPP under the guaranty agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM’s alleged failures. LPP did not quantify the amount of indemnification being sought, which could be material. The Company believes the indemnification claims are without merit and intends to vigorously defend against such claims.

In addition, WBI Holdings has guaranteed certain of Fidelity’s natural gas and oil price swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements at June 30, 2009, expire in the years ranging from 2009 to 2011; 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. There was no amount outstanding by Fidelity at June 30, 2009. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts, a conditional purchase agreement and certain other guarantees. At June 30, 2009, the fixed maximum amounts guaranteed under these agreements aggregated $194.3 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $98.2 million in 2009; $60.8 million in 2010; $24.8 million in 2011; $2.7 million in 2012; $1.2 million in 2013; $200,000 in 2014; $1.2 million in 2018; $1.2 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $500,000 and was reflected on the Consolidated Balance Sheet at June 30, 2009. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, materials obligations, natural gas transportation agreements and other agreements that guarantee the performance of other subsidiaries of the Company. At June 30, 2009, the fixed maximum amounts guaranteed under these letters of credit, aggregated $40.9 million. In 2009 and 2010, $33.9 million and $7.0 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at June 30, 2009.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands. At June 30, 2009, the fixed maximum amounts guaranteed under these agreements aggregated $24.0 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $20.0 million in 2009 and $4.0 million in 2011. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was $1.6 million, which was not reflected on the Consolidated Balance Sheet at June 30, 2009, 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 June 30, 2009.

In the normal course of business, Centennial has purchased surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of June 30, 2009, approximately $695.8 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

19. Subsequent events

The Company evaluated for events or transactions between the balance sheet date and August 7, 2009, the date of the issuance of the financial statements, that would require recognition or disclosure in the financial statements.

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. Although volatility and disruptions in the capital markets have increased significantly, the Company continues to issue commercial paper to meet its current needs. If access to the commercial paper markets were to become unavailable, the Company may need to borrow under its credit agreements. At that time, accessing the long-term debt market may be more challenging and result in significantly higher interest rates. As a result, the Company has increased its focus on the use of operating cash flows to substantially fund capital expenditures. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments.

The key strategies for each of the Company's business segments and certain related business challenges are summarized below. For a summary of the Company's business segments, see Note 15.

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, including electric generation build-out, and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment.

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, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of electric generating facilities and transmission lines are subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which may necessitate increases in electric energy prices.

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

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls, retention of key personnel, managing through downturns in the economy and effective management of working capital are ongoing challenges.

Pipeline and Energy Services
Strategy Utilize 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, transmission and storage facilities; and incremental expansion of pipeline capacity to allow customers access to more liquid and higher-priced markets.

Challenges Challenges for this segment include: energy price volatility; natural gas basis differentials; regulatory requirements; recruitment and retention of a skilled workforce; and competition from other natural gas pipeline and gathering companies.

Natural Gas and Oil Production
Strategy Apply technology and utilize 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 expand 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 Volatility 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, materials, auxiliary equipment and industry-related field services, and inflationary pressure on development and operating costs, all primarily in a higher price environment; and competition from other natural gas and oil companies are ongoing challenges for this segment.

Construction Materials and Contracting
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), and negotiation of contract price escalation provisions. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access

to adequate quantities of permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its presence, through acquisition, in the higher-margin materials business (rock, sand, gravel, liquid asphalt, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges The economic downturn has adversely impacted operations, particularly in the private market. This business unit expects to continue cost containment efforts and a greater emphasis on industrial, energy and public works projects. Significant volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel continue to be a concern. Increased competition in certain construction markets has also lowered margins.

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 2008 Annual Report. For further information on each segment's key growth strategies, projections and certain assumptions, see Prospective Information. For information pertinent to various commitments and contingencies, see Notes to Consolidated Financial Statements.

Earnings Overview

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Dollars in millions, where applicable)			
Electric	$3.2	$2.8	$8.3	$8.3
Natural gas distribution	(4.8)	5.4	19.1	21.8
Construction services	6.9	14.1	15.6	24.9
Pipeline and energy services	10.9	6.8	17.3	14.0
Natural gas and oil production	20.8	71.7	(352.5)	122.3
Construction materials and contracting	16.0	12.7	.3	(8.4)
Other	2.1	1.8	3.1	3.3
Earnings (loss) on common stock	$55.1	$115.3	$(288.8)	$186.2
Earnings (loss) per common share – basic	$.30	$.63	$(1.57)	$1.02
Earnings (loss) per common share – diluted	$.30	$.63	$(1.57)	$1.01
Return on average common equity for the 12 months ended			(6.9)%	19.3%

Three Months Ended June 30, 2009 and 2008 Consolidated earnings for the quarter ended June 30, 2009, decreased $60.2 million from the comparable prior period largely due to:

- Lower average realized natural gas prices and oil prices of 43 percent and 56 percent, respectively, as well as decreased natural gas production of 14 percent, partially offset by lower production taxes and lower depreciation, depletion and amortization expense at the natural gas and oil production business

- Absence of a $4.4 million (after tax) gain on the sale of Cascade's natural gas management service in June 2008, decreased retail sales volumes, as well as a seasonal loss of $2.1 million (after tax) at Intermountain, which was acquired in October 2008, at the natural gas distribution business
  - Lower construction workloads, partially offset by higher margins at the construction services business

Partially offsetting these decreases were:

- Lower operation and maintenance expense and increased transportation volumes at the pipeline and energy services business
- Lower selling, general and administrative expense and increased earnings from liquid asphalt oil and related products, partially offset by lower aggregate and ready-mixed concrete sales volumes and margins at the construction materials and contracting business

Six Months Ended June 30, 2009 and 2008 Consolidated earnings for the six months ended June 30, 2009, decreased $475.0 million primarily due to:

- A noncash write-down of natural gas and oil properties of $384.4 million (after tax), as well as lower average realized natural gas prices and oil prices of 35 percent and 58 percent, respectively, and decreased natural gas production of 10 percent
- Lower construction workloads, partially offset by higher construction margins and lower general and administrative expense at the construction services business

Partially offsetting these decreases were lower selling, general and administrative expense and increased earnings from liquid asphalt oil and related products, partially offset by lower aggregate and ready-mixed concrete sales volumes and margins at the construction materials and contracting business.

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

Electric

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Dollars in millions, where applicable)			
Operating revenues	$44.5	$45.9	$95.8	$98.1
Operating expenses:				
Fuel and purchased power	15.2	15.7	33.9	34.5
Operation and maintenance	15.9	16.5	31.5	31.4
Depreciation, depletion and amortization	6.0	6.1	12.2	12.1
Taxes, other than income	2.3	2.2	4.7	4.4
	39.4	40.5	82.3	82.4
Operating income	5.1	5.4	13.5	15.7
Earnings	$3.2	$2.8	$8.3	$8.3
Retail sales (million kWh)	595.3	577.7	1,320.1	1,285.5
Sales for resale (million kWh)	22.8	51.5	32.5	99.9
Average cost of fuel and purchased power per kWh	$.023	$.024	$.024	$.024

Three Months Ended June 30, 2009 and 2008 Electric earnings increased $400,000 (17 percent) due to:

- Higher other income, primarily allowance for funds used during construction of $1.0 million (after tax)
- Lower operation and maintenance expense of $300,000 (after tax), largely payroll-related costs
- Higher electric retail sales margins due to increased retail sales volumes of 3 percent

Partially offsetting these increases was decreased sales for resale margins due to lower average rates of 49 percent and decreased volumes of 56 percent due to lower market demand and decreased plant generation.

Six Months Ended June 30, 2009 and 2008 Electric earnings were unchanged from the comparable prior year period due to:

- Higher electric retail sales margins due to increased retail sales volumes of 3 percent
- Higher other income, primarily allowance for funds used during construction of $1.5 million (after tax)

Offset by:

- Decreased sales for resale margins due to lower average rates of 48 percent and decreased volumes of 68 percent due to lower market demand and decreased plant generation
- Higher interest expense of $500,000 (after tax)

Natural Gas Distribution

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Dollars in millions, where applicable)			
Operating revenues	$164.1	$197.0	$647.3	$559.1
Operating expenses:				
Purchased natural gas sold	107.5	137.4	473.5	420.0
Operation and maintenance	35.5	28.7	73.6	55.7
Depreciation, depletion and amortization	10.6	7.2	21.3	14.3
Taxes, other than income	11.3	11.0	34.2	25.6
	164.9	184.3	602.6	515.6
Operating income (loss)	(.8)	12.7	44.7	43.5
Earnings (loss)	$(4.8)	$5.4	$19.1	$21.8
Volumes (MMdk):				
Sales	14.1	15.4	57.7	46.6
Transportation	23.4	18.5	57.4	45.1
Total throughput	37.5	33.9	115.1	91.7
Degree days (% of normal)*				
Montana-Dakota	119%	117%	106%	104%
Cascade	100%	120%	105%	111%
Intermountain	103%	---	105%	---
Average cost of natural gas, including transportation, per dk**	$7.61	$8.90	$8.20	$8.11

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

** Regulated natural gas sales only.

Note: Intermountain was acquired on October 1, 2008.

Three Months Ended June 30, 2009 and 2008 Earnings at the natural gas distribution business decreased $10.2 million compared to the prior year due to:

- Absence of a $4.4 million (after tax) gain on the sale of Cascade’s natural gas management service in June 2008
- Decreased retail sales volumes at existing operations, largely resulting from warmer weather than last year in the Northwest
- Seasonal loss of $2.1 million (after tax) at Intermountain, which was acquired in October 2008
- Operational integration costs of $800,000 (after tax)

Six Months Ended June 30, 2009 and 2008 Earnings at the natural gas distribution business decreased $2.7 million due to:

- Absence of a gain on the sale of Cascade’s natural gas management service, as previously discussed
- Decreased retail sales volumes at existing operations, as previously discussed
- Operational integration costs of $1.3 million (after tax)

Partially offsetting these decreases were earnings at Intermountain of $5.7 million (after tax), which was acquired in October 2008.

Construction Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Operating revenues	$220.7	$324.7	$465.5	$632.1
Operating expenses:				
Operation and maintenance	199.2	286.6	416.4	560.5
Depreciation, depletion and amortization	3.3	3.1	6.7	6.5
Taxes, other than income	6.4	10.4	16.0	22.4
	208.9	300.1	439.1	589.4
Operating income	11.8	24.6	26.4	42.7
Earnings	$6.9	$14.1	$15.6	$24.9

Three Months Ended June 30, 2009 and 2008 Construction services earnings decreased $7.2 million (51 percent) due to lower construction workloads, partially offset by higher margins, largely in the Southwest region.

Six Months Ended June 30, 2009 and 2008 Construction services earnings decreased $9.3 million (37 percent) over the comparable prior period due to lower construction workloads, largely in the Southwest region. Partially offsetting this decrease were higher construction margins in certain regions, as well as lower general and administrative expense of $1.0 million (after tax), largely payroll-related.

Pipeline and Energy Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Dollars in millions)			
Operating revenues	$68.0	$155.1	$153.1	$288.9
Operating expenses:				
Purchased natural gas sold	28.1	116.6	74.2	210.7
Operation and maintenance	11.1	16.7	28.8	34.3
Depreciation, depletion and amortization	6.2	5.9	12.3	11.5
Taxes, other than income	3.0	2.8	5.9	5.6
	48.4	142.0	121.2	262.1
Operating income	19.6	13.1	31.9	26.8
Earnings	$10.9	$6.8	$17.3	$14.0
Transportation volumes (MMdk):				
Montana-Dakota	10.2	7.2	18.5	15.5
Other	33.6	26.8	62.4	48.2
	43.8	34.0	80.9	63.7
Gathering volumes (MMdk)	24.3	25.5	48.6	49.5

Three Months Ended June 30, 2009 and 2008 Pipeline and energy services earnings increased $4.1 million (59 percent) due to:

- Lower operation and maintenance expense, largely related to the settlement of the natural gas storage litigation. For further information regarding natural gas storage litigation, see Note 18.
- Increased transportation volumes of $1.5 million (after tax), largely volumes transported to storage

Results also reflect lower operating revenues, as well as lower purchased natural gas sold related to lower natural gas prices.

Six Months Ended June 30, 2009 and 2008 Pipeline and energy services earnings increased $3.3 million (23 percent) due to:

- Increased transportation volumes of $3.0 million (after tax), largely volumes transported to storage
- Lower operation and maintenance expense, largely related to the settlement of the natural gas storage litigation, as previously discussed
- Higher gathering rates of $1.1 million (after tax)

Partially offsetting the earnings increase were:

- Lower storage services revenues of $1.4 million (after tax), resulting from lower withdrawals and lower rates
- Decreased gathering volumes of 2 percent

Results also reflect lower operating revenues, as well as lower purchased natural gas sold related to lower natural gas prices. The above table also reflects lower operation and maintenance expense and revenues related to energy-related service projects.

Natural Gas and Oil Production

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(Dollars in millions, where applicable)			
Operating revenues:				
Natural gas	$69.2	$140.5	$150.9	$258.0
Oil	35.6	74.6	60.0	126.7
Other	---	.1	---	.1
	104.8	215.2	210.9	384.8
Operating expenses:				
Purchased natural gas sold	---	.1	---	.1
Operation and maintenance:				
Lease operating costs	18.0	19.2	38.0	37.5
Gathering and transportation	6.1	6.2	12.2	11.9
Other	10.7	13.7	21.0	22.6
Depreciation, depletion and amortization	30.2	41.7	72.8	81.0
Taxes, other than income:				
Production and property taxes	5.7	16.3	13.2	29.9
Other	.2	.3	.4	.5
Write-down of natural gas and oil properties	---	---	620.0	---
	70.9	97.5	777.6	183.5
Operating income (loss)	33.9	117.7	(566.7)	201.3
Earnings (loss)	$20.8	$71.7	$(352.5)	$122.3
Production:				
Natural gas (MMcf)	14,297	16,531	29,698	33,092
Oil (MBbls)	771	717	1,513	1,338
Total Production (MMcf equivalent)	18,923	20,830	38,775	41,118
Average realized prices (including hedges):				
Natural gas (per Mcf)	$4.84	$8.50	$5.08	$7.80
Oil (per barrel)	$46.21	$104.19	$39.67	$94.72
Average realized prices (excluding hedges):				
Natural gas (per Mcf)	$2.40	$9.33	$3.04	$8.11
Oil (per barrel)	$47.46	$105.34	$40.30	$95.60
Average depreciation, depletion and amortization rate, per equivalent Mcf	$1.52	$1.94	$1.80	$1.91
Production costs, including taxes, per equivalent Mcf:				
Lease operating costs	$.95	$.92	$.98	$.91
Gathering and transportation	.32	.30	.31	.29
Production and property taxes	.30	.78	.34	.73
	$1.57	$2.00	$1.63	$1.93

Three Months Ended June 30, 2009 and 2008 Natural gas and oil production experienced a decrease in earnings of $50.9 million (71 percent) due to:

- Lower average realized natural gas prices and oil prices of 43 percent and 56 percent, respectively
- Decreased natural gas production of 14 percent, largely related to normal production declines at certain properties

Partially offsetting these decreases were:

- Lower production taxes of $6.6 million (after tax) associated largely with lower average prices
- Lower depreciation, depletion and amortization expense of $7.1 million (after tax), due to lower depletion rates and decreased combined production. The lower depletion rates are largely the result of the write-downs of natural gas and oil properties in December 2008 and March 2009.
- Lower general and administrative expense of $1.9 million (after tax)
- Increased oil production of 8 percent, largely related to drilling activity in the Bakken area

Six Months Ended June 30, 2009 and 2008 Natural gas and oil production experienced a decrease in earnings of $474.8 million due to:

- A noncash write-down of natural gas and oil properties of $384.4 million (after tax), as discussed in Note 6
- Lower average realized natural gas prices and oil prices of 35 percent and 58 percent, respectively
- Decreased natural gas production of 10 percent, largely related to normal production declines at certain properties

Partially offsetting these decreases were:

- Lower production taxes of $10.4 million (after tax) associated largely with lower average prices
- Lower depreciation, depletion and amortization expense of $5.1 million (after tax), due to lower depletion rates and decreased combined production. The lower depletion rates are largely the result of the write-downs of natural gas and oil properties in December 2008 and March 2009.
- Increased oil production of 13 percent, largely related to drilling activity in the Bakken area

Construction Materials and Contracting

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(Dollars in millions)			
Operating revenues	$389.4	$427.4	$572.9	$628.7
Operating expenses:				
Operation and maintenance	325.7	366.1	498.0	561.3
Depreciation, depletion and amortization	23.8	25.4	47.8	50.9
Taxes, other than income	9.8	10.4	17.3	19.5
	359.3	401.9	563.1	631.7
Operating income (loss)	30.1	25.5	9.8	(3.0)
Earnings (loss)	$16.0	$12.7	$.3	$(8.4)
Sales (000's):				
Aggregates (tons)	6,486	8,719	9,671	12,960
Asphalt (tons)	1,530	1,452	1,718	1,648
Ready-mixed concrete (cubic yards)	792	1,052	1,301	1,663

Three Months Ended June 30, 2009 and 2008 Earnings at the construction materials and contracting business increased $3.3 million (26 percent) due to:

- Lower selling, general and administrative expense of $4.9 million (after tax), largely the result of cost reduction measures
- Increased earnings from liquid asphalt oil and related products, due to higher margins
- Lower depreciation, depletion and amortization expense of $1.0 million (after tax), largely the result of lower property, plant and equipment balances

Partially offsetting the increases were lower aggregate and ready-mixed concrete sales volumes and margins as a result of the continuing economic downturn.

Six Months Ended June 30, 2009 and 2008 Construction materials and contracting earnings increased $8.7 million due to:

- Lower selling, general and administrative expense of $9.0 million (after tax), as previously discussed
- Increased earnings from liquid asphalt oil and related products, due to higher margins
- Lower depreciation, depletion and amortization expense of $1.9 million (after tax), largely the result of lower property, plant and equipment balances

Partially offsetting the increases were lower aggregate and ready-mixed concrete sales volumes and margins as a result of the continuing economic downturn.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Other:				
Operating revenues	$2.7	$2.7	$5.4	$5.3
Operation and maintenance	1.9	2.8	5.2	5.5
Depreciation, depletion and amortization	.3	.3	.6	.6
Taxes, other than income	.1	.1	.1	.1
Intersegment transactions:				
Operating revenues	$36.2	$116.2	$98.9	$223.3
Purchased natural gas sold	29.2	109.0	84.8	209.1
Operation and maintenance	7.0	7.2	14.1	14.2

For further information on intersegment eliminations, see Note 15.

PROSPECTIVE INFORMATION
The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for certain 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 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 2008 Annual Report. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's growth and earnings projections.

MDU Resources Group, Inc.
- Earnings per common share for 2009, diluted, are projected in the range of $1.05 to $1.30 excluding a $384.4 million, or $2.09 per common share first quarter after-tax noncash charge related to low natural gas and oil prices. (Including the first quarter noncash charge, guidance for 2009 is a loss of $.79 to $1.04 per common share.)

- The Company expects the percentage of 2009 earnings per common share by quarter, excluding the first quarter noncash charge, to be in the following approximate ranges:
  - Third quarter – 30 percent to 35 percent
  - Fourth quarter – 20 percent to 25 percent

- While 2009 earnings per share are projected to decline compared to 2008 earnings, long-term compound annual growth goals on earnings per share from operations are in the range of 7 percent to 10 percent.

Electric
- In April 2009, the Company purchased a 25 MW ownership interest in the Wygen III power generation facility which is under construction near Gillette, Wyoming. This rate-based

generation will replace a portion of the purchased power for the Wyoming system. The plant is expected to be online June 2010.

- The Company plans to develop additional wind generation including a 19.5 MW wind generation facility in southwest North Dakota and a 10.5 MW expansion of the Diamond Willow wind facility near Baker, Montana. Both projects are expected to be commercial third quarter 2010.

- The Company is analyzing potential projects for accommodating load growth and replacing an expired purchased power contract with company-owned generation, which will add to base-load capacity. The Company is a participant in the Big Stone II project. All major permits for this project have been obtained with the exception of the EIS, which is expected to be final during the third quarter. The Company anticipates owning at least 116 MW of this plant, which is projected to be completed in 2015. In the event the participants decide not to proceed with construction, the Company is reviewing alternatives, including the construction of certain natural gas-fired combustion generation.

Natural gas distribution

- The labor contract that Cascade was negotiating with the bargaining unit consisting of 35 customer service representatives and credit and collections clerks, as reported in Items 1 and 2 – Business and Properties – General in the 2008 Annual Report, has been ratified. Negotiations by Cascade of an agreement with the field operations group, consisting of 177 employees, as reported in Items 1 and 2 – Business and Properties – General in the 2008 Annual Report, have reached an impasse.

Construction services

- The Company anticipates margins in 2009 to be comparable to 2008.

- The Company continues to focus on costs and efficiencies to enhance margins. With its highly skilled technical workforce, this group is prepared to take advantage of government stimulus spending on transmission infrastructure.

- Work backlog as of June 30, 2009, was approximately $507 million, compared to $655 million at June 30, 2008, and $557 million at March 31, 2009. Approximately 35 percent of the June 30, 2009 backlog is related to project work for Fontainebleau Las Vegas LLC, which filed a voluntary petition for reorganization under Chapter 11 of the United States Bankruptcy Code.

- This business continually seeks opportunities to expand through strategic acquisitions and organic growth opportunities.

Pipeline and energy services

- An incremental expansion to the Grasslands Pipeline of 75,000 Mcf per day is in process with a projected in-service date of September 2009. Through additional compression, the firm capacity of the Grasslands Pipeline will reach ultimate full capacity of 213,000 Mcf per day, an increase from the current firm capacity of 138,000 Mcf per day.

- In 2009, total gathering and transportation throughput is expected to be slightly higher than 2008 record levels.

- The Company continues to pursue expansion of facilities and services offered to customers.

Natural gas and oil production

- As the result of lower natural gas and oil prices, the Company has reduced its 2009 capital expenditures for this segment to approximately $170 million. At this level of investment, the Company expects its combined natural gas and oil production to be 7 percent to 10 percent lower than 2008 levels.

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

Index*	Price Per Mcf
Ventura	$3.50 to $4.00
NYMEX	$3.75 to $4.25
CIG	$2.50 to $3.00

* 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.

- Earnings guidance reflects estimated NYMEX crude oil prices for August through December in the range of $58 to $63 per barrel.

- For the last six months of 2009, the Company has hedged approximately 45 percent to 50 percent of its estimated natural gas production and 30 percent to 35 percent of its estimated oil production. For 2010, the Company has hedged approximately 25 percent to 30 percent of its estimated natural gas production and 25 percent to 30 percent of its estimated oil production. For 2011, the Company has hedged less than 5 percent of its estimated natural gas production. The hedges that are in place as of August 3, 2009, are summarized in the following chart:

Commodity	Type	Index*	Period Outstanding	Forward Notional Volume (MMBtu/Bbl)	Price (Per MMBtu/Bbl)
Natural Gas	Swap	HSC	7/09 - 12/09	1,251,200	$8.16
Natural Gas	Collar	Ventura	7/09 - 12/09	736,000	$7.90-$8.54
Natural Gas	Collar	Ventura	7/09 - 12/09	2,208,000	$8.25-$8.92
Natural Gas	Swap	Ventura	7/09 - 12/09	1,840,000	$9.02
Natural Gas	Collar	CIG	7/09 - 12/09	1,840,000	$6.50-$7.20
Natural Gas	Swap	CIG	7/09 - 12/09	460,000	$7.27
Natural Gas	Collar	NYMEX	7/09 - 12/09	920,000	$8.75-$10.15
Natural Gas	Swap	Ventura	7/09 - 12/09	1,840,000	$9.20
Natural Gas	Collar	NYMEX	7/09 - 12/09	1,840,000	$11.00-$12.78
Natural Gas	Swap	HSC	1/10 - 12/10	1,606,000	$8.08
Natural Gas	Swap	NYMEX	1/10 - 12/10	3,650,000	$6.18
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$6.40
Natural Gas	Collar	NYMEX	1/10 - 12/10	1,825,000	$5.63-$6.00
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$5.855
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$6.045
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$6.045
Natural Gas	Collar	NYMEX	1/10 - 3/11	2,275,000	$5.62-$6.50
Natural Gas	Swap	HSC	1/11 - 12/11	1,350,500	$8.00
Crude Oil	Swap	NYMEX	7/09 - 12/09	276,000	$57.02
Crude Oil	Collar	NYMEX	7/09 - 12/09	184,000	$54.00-$60.00
Crude Oil	Collar	NYMEX	1/10 - 12/10	365,000	$60.00-$75.00
Crude Oil	Swap	NYMEX	1/10 - 12/10	365,000	$73.20
Natural Gas	Basis	NYMEX to	7/09 - 12/09	1,840,000	$0.61

Natural Gas	Basis	Ventura NYMEX to Ventura	1/10 - 12/10	3,650,000	$0.25
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	912,500	$0.245
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	4,562,500	$0.25
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	1,825,000	$0.225
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	912,500	$0.23
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	2,737,500	$0.23
Natural Gas	Basis	NYMEX to Ventura	1/11 - 3/11	450,000	$0.135

* 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; HSC is the Houston Ship Channel hub in southeast Texas which connects to several pipelines.

Construction materials and contracting

- The economic slowdown and substantially higher energy prices adversely impacted operations in 2008. Although the Company predicts that this economic slowdown will continue through 2009, it is expected that earnings will be higher than 2008 primarily the result of cost reduction

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measures put in place during 2008 and substantially lower diesel costs expected in 2009 compared to 2008.

- The Company continues its strong emphasis on cost containment throughout the organization. In addition, the Company is well positioned to take advantage of government stimulus spending on transportation infrastructure.

- Work backlog as of June 30, 2009, was approximately $707 million, compared to $634 million at June 30, 2008, and $574 million at March 31, 2009. The backlog includes several public works projects. Although public project margins tend to be somewhat lower than private construction related work, the Company anticipates significant contributions to revenue from an increase in public works volume.

- As the country's 8th largest aggregate producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in its markets.

- Of the two labor contracts that Knife River was negotiating, as reported in Items 1 and 2 – Business and Properties – General in the 2008 Annual Report, one has been ratified. The other remaining contract is still in negotiations.

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Note 9, 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, pension and other postretirement benefits, and income taxes. There were no material changes in the Company's critical accounting policies involving significant estimates from those reported in the 2008 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2008 Annual Report.

LIQUIDITY AND CAPITAL COMMITMENTS

Cash flows

Operating activities The changes in cash flows from operating activities generally follow the results of operations as discussed in Financial and Operating Data and also are affected by changes in working capital.

Cash flows provided by operating activities in the first six months of 2009 increased $159.6 million from the comparable 2008 period. Lower working capital requirements of $271.1 million (including lower receivables and lower natural gas costs recoverable through rate adjustments, partially offset by lower accounts payable) were partially offset by lower income before depreciation, depletion and amortization and before the after-tax noncash write-down of natural gas and oil properties.

Investing activities Cash flows used in investing activities in the first six months of 2009 decreased $278.9 million from the comparable period in 2008 due to:

- Lower cash used for acquisitions of $267.4 million, primarily at the natural gas and oil production business

- Decreased ongoing capital expenditures of $113.1 million, largely at the natural gas and oil production and construction materials and contracting businesses
- Decreased cash provided from the sale of investments

Financing activities Cash flows provided by financing activities in the first six months of 2009 decreased $432.3 million from the comparable period in 2008 due to lower issuance of long-term debt, higher repayment of short-term borrowings and lower issuance of short-term borrowings.

Defined benefit pension plans
There were no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2008 Annual Report. For further information, see Note 16 and Part II, Item 7 in the 2008 Annual Report.

Capital expenditures
Net capital expenditures for the first six months of 2009 were $240.6 million and are estimated to be approximately $415 million for 2009. The decrease, as compared to 2009 estimated capital expenditures of $602 million, as reported in Part II, Item 7 of the Company's 2008 Annual Report, is largely related to lower expenditures at the natural gas and oil production business and electric and natural gas distribution businesses. Estimated capital expenditures include:

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

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 2009 capital expenditures referred to previously. The Company has increased its focus on the use of operating cash flows to substantially fund capital expenditures. In addition, the Company has capabilities to fund capital expenditures through various sources, including the Company's credit facilities, as described below, and through the issuance of long-term debt and the Company's equity securities.

Capital resources
Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at June 30, 2009. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling $125 million (with provision for an increase, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement at June 30, 2009. The credit agreement supports the Company's $125 million commercial

paper program. Although volatility in the capital markets has increased significantly, the Company continues to issue commercial paper to meet its current needs. Under the Company’s commercial paper program, $51.9 million was outstanding at June 30, 2009. 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. Recent downgrades in the Company’s credit ratings have not limited, nor are currently expected to limit, the Company’s ability to access the capital markets, although it may experience an increase in overall interest rates with respect to its cost of borrowings. If the Company were to experience a further downgrade of its credit ratings, it may need to borrow under its credit agreement.

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

In order to borrow under the Company’s credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of the Company’s credit agreement, see Part II, Item 8 – Note 10, in the 2008 Annual Report.

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 Mortgage and, in some cases, to certify to the trustee that annual earnings (pretax and before interest charges), as defined in the Mortgage, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the tests, as of June 30, 2009, the Company could have issued approximately $667 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred stock dividends was 5.3 times for the 12 months ended December 31, 2008. Due to the $84.2 million and $384.4 million after-tax noncash write-downs of natural gas and oil properties in the fourth quarter of 2008 and the first quarter of 2009, respectively, earnings were insufficient by $332.1 million to cover fixed charges for the 12 months ended June 30, 2009. If the $84.2 million and $384.4 million after-tax noncash write-downs are excluded, the coverage of fixed charges including preferred stock dividends would have been 4.9 times for the 12 months ended June 30, 2009. Common stockholders' equity as a percent of total capitalization was 59 percent and 61 percent at June 30, 2009 and December 31, 2008, respectively.

The coverage of fixed charges including preferred stock dividends that excludes the effect of the after-tax noncash write-downs of natural gas and oil properties is a non-GAAP financial measure. The Company believes that this non-GAAP financial measure is useful because the write-downs excluded are not indicative of the Company’s cash flows available to meet its fixed charges obligations. The presentation of this additional information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

The Company has repurchased, and may from time to time seek to repurchase, outstanding first mortgage bonds through open market purchases or privately negotiated transactions. The Company will evaluate any such transactions in light of then existing market conditions, taking into account its liquidity and prospects for future access to capital. As of June 30, 2009, the Company had $35.5 million of first mortgage bonds outstanding, $30.0 million of which were held by the Indenture trustee for the benefit of the senior note holders. The aggregate principal amount of the Company’s outstanding first mortgage bonds, other than those held by the Indenture trustee, is $5.5 million and satisfies the lien release requirements under the Indenture. As a result, the Company may at any time, subject to satisfying certain specified conditions, require that any debt issued under its Indenture become unsecured and rank equally with all of the Company’s other unsecured and unsubordinated debt (as of June 30, 2009, 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).

In September 2008, the Company entered into a Sales Agency Financing Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 5,000,000 shares of the Company’s common stock. 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 May 28, 2011. 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 Company has not issued any stock under the Sales Agency Financing Agreement through June 30, 2009.

The Company currently has authorization to issue and sell up to $1.0 billion of securities pursuant to a registration statement on file with the SEC. The Company may sell all or a portion of such securities if warranted by market conditions and the Company's capital requirements. Any offer and sale of such securities will be made only by means of a prospectus meeting the requirements of the Securities Act and the rules and regulations thereunder.

MDU Energy Capital, LLC MDU Energy Capital has a master shelf agreement that allows for borrowings up to $175 million. Under the terms of the master shelf agreement, $165.0 million was outstanding at June 30, 2009. MDU Energy Capital may incur additional indebtedness under the master shelf agreement until the earlier of August 14, 2010, or such time as the agreement is terminated by either of the parties thereto.

In order to borrow under its master shelf agreement, MDU Energy Capital must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of the MDU Energy Capital master shelf agreement, see Part II, Item 8 – Note 10, in the 2008 Annual Report.

Cascade Natural Gas Corporation Cascade has a revolving credit agreement with various banks totaling $50 million with certain provisions allowing for increased borrowings, up to a maximum of $75 million. The credit agreement expires on December 28, 2012, with provisions allowing for an extension of up to two years upon consent of the banks. Under the terms of the credit agreement, there were no outstanding borrowings at June 30, 2009. As of June 30, 2009, there were outstanding letters of credit, as discussed in Note 18, of which $1.9 million reduced amounts available under the credit agreement.

In order to borrow under Cascade's credit agreement, Cascade must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of Cascade's credit agreement, see Part II, Item 8 – Note 9, in the 2008 Annual Report.

Cascade's credit agreement contains cross-default provisions. For information on the cross-default provisions of this agreement, see Part II, Item 8 – Note 9, in the 2008 Annual Report.

Intermountain Gas Company Intermountain has a revolving credit agreement with various banks totaling $65 million with certain provisions allowing for increased borrowings, up to a maximum of $70 million. The credit agreement expires on August 31, 2010. Under the terms of the credit agreement, $7.8 million was outstanding at June 30, 2009.

In order to borrow under Intermountain’s credit agreement, Intermountain must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of Intermountain’s credit agreement, see Part II, Item 8 – Note 10, in the 2008 Annual Report.

Intermountain’s credit agreement contains cross-default provisions. For information on the cross-default provisions of this agreement, see Part II, Item 8 – Note 10, in the 2008 Annual Report.

Centennial Energy Holdings, Inc. Centennial has a revolving credit agreement with various banks and institutions totaling $400 million with certain provisions allowing for increased borrowings. The credit agreement supports Centennial’s $400 million commercial paper program. Although volatility in the capital markets has increased significantly, the Company continues to issue commercial paper to meet its current needs. There were no outstanding borrowings under the Centennial credit agreement at June 30, 2009. Under the Centennial commercial paper program, $138.0 million was outstanding at June 30, 2009. 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 the credit agreement). The revolving credit agreement includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of $450 million and expires on December 13, 2012. As of June 30, 2009, Centennial had letters of credit outstanding, as discussed in Note 18, of which $26.4 million reduced amounts available under the agreement.

Centennial has an uncommitted long-term master shelf agreement that allowed for borrowings of up to $550 million. Under the terms of the master shelf agreement, $524.0 million was outstanding at June 30, 2009. The ability to request additional borrowings under this master shelf agreement expired 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. Given its recent credit ratings downgrades and depending on future credit market conditions, Centennial may experience an increase in overall interest rates with respect to its cost of borrowings and may need to borrow under its committed bank lines.

Prior to the maturity of the Centennial credit agreement, Centennial expects that it will negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event Centennial was unable to successfully negotiate this agreement, or in the event the fees on this facility become too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

In order to borrow under Centennial’s credit agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions of Centennial’s credit agreement, see Part II, Item 8 – Note 10, in the 2008 Annual Report.

Certain of Centennial’s financing agreements contain cross-default provisions. For information on the cross-default provisions of these agreements, see Part II, Item 8 – Note 10, in the 2008 Annual Report.

Williston Basin Interstate Pipeline Company Williston Basin has an uncommitted long-term private shelf agreement that allows for borrowings up to $125 million. Under the terms of the private shelf agreement, $87.5 million was outstanding at June 30, 2009, consisting of $35.0 million of notes issued under the private shelf agreement and $52.5 million of notes issued under a master shelf agreement that expired in December 2008. The ability to request additional borrowings under this private shelf agreement expires on December 23, 2010, with certain provisions allowing for an extension to December 23, 2011.

In order to borrow under its uncommitted long-term private shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions. For information on the covenants and certain other conditions for the uncommitted long-term private shelf agreement, see Part II, Item 8 – Note 10, in the 2008 Annual Report.

Off balance sheet arrangements

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses that Petrobras may incur from certain contingent liabilities specified in the purchase agreement. For further information, see Note 18.

Centennial continues to guarantee CEM's obligations under a construction contract for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. For further information, see Note 18.

Contractual obligations and commercial commitments

There are no material changes in the Company’s contractual obligations relating to long-term debt, estimated interest payments, operating leases, purchase commitments and uncertain tax positions from those reported in the 2008 Annual Report.

For more information on contractual obligations and commercial commitments, see Part II, Item 7 in the 2008 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 and basis differentials on forecasted sales of natural gas and oil production. Cascade and Intermountain utilize derivative instruments to manage a portion of their regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas. For more information on derivative instruments and commodity price risk, see Part II, Item 7A in the 2008 Annual Report, and Notes 10 and 13.

The following table summarizes derivative agreements entered into by Fidelity, Cascade and Intermountain as of June 30, 2009. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade and Intermountain to receive variable prices and pay fixed prices.

(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas swap agreements maturing in 2009	$8.73	5,391	$25,446
Natural gas swap agreements maturing in 2010	$6.67	7,081	$4,739
Natural gas swap agreement maturing in 2011	$8.00	1,351	$1,828
Natural gas basis swap agreement maturing in 2009	$ .61	1,840	$(480)
Natural gas basis swap agreements maturing in 2010	$ .24	11,863	$(218)
Oil swap agreement maturing in 2009	$57.02	276	$(4,105)
Oil swap agreement maturing in 2010	$73.20	365	$(777)
Cascade			
Natural gas swap agreements maturing in 2009	$7.95	7,544	$(21,974)
Natural gas swap agreements maturing in 2010	$8.03	8,922	$(25,158)
Natural gas swap agreements maturing in 2011	$8.10	2,270	$(4,553)
Intermountain			
Natural gas swap agreements maturing in 2009	$3.78	11,774	$(6,732)
Natural gas swap agreements maturing in 2010	$5.57	3,290	$(976)

	Weighted Average Floor/Ceiling Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas collar agreements maturing in 2009	$8.52/$9.55	7,544	$34,251
Oil collar agreement maturing in 2009	$54.00/$60.00	184	$(2,343)
Oil collar agreement maturing in 2010	$60.00/$75.00	365	$(2,145)

Note: The fair value of Cascade’s natural gas swap agreements is presented net of the collateral provided to the counterparties of $8.5 million.

Interest rate risk

There were no material changes to interest rate risk faced by the Company from those reported in the 2008 Annual Report. For more information, see Part II, Item 7A in the 2008 Annual Report.

At June 30, 2009 and 2008, and December 31, 2008, 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, see Part II, Item 8 – Note 4 in the 2008 Annual Report.

At June 30, 2009 and 2008, and December 31, 2008, 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. The Company's controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. 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 at a reasonable assurance level.

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 quarter ended June 30, 2009, 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 18, 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 in the 2008 Annual Report other than the risk related to economic volatility; the risk of exposure to credit risk; the risk related to backlog; the risk related to environmental laws and regulations; the risk associated with electric generation operation that could be adversely impacted by global climate change initiatives to reduce GHG emissions; and the risk related to litigation and administrative proceedings in connection with CBNG development activities. In addition, Part I, Item 1A – Risk Factors in the 2008 Annual Report included a risk factor for litigation between the Company’s subsidiary and a nonaffiliated natural gas producer that had been conducting drilling and production operations that the subsidiary believed was causing diversion and loss of quantities of storage gas from one of its storage reservoirs. In July 2009, the parties resolved the litigation and have agreed to dismiss the suit. 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.

Economic Risks

The Company relies on financing sources and capital markets. Access to these markets may be adversely affected by factors beyond the Company's control. If the Company is unable to obtain economic financing in the future, the Company's ability to execute its business plans, make capital expenditures or pursue acquisitions that the Company may otherwise rely on for future growth could be impaired. As a result, the market value of the Company's common stock may be adversely affected. If the Company issues a substantial amount of common stock it could have a dilutive effect on its existing shareholders.

The Company relies on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as sources of liquidity for capital requirements not satisfied by its cash flow from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans may be adversely affected. Market disruptions, such as those currently being experienced in the United States and abroad, or a further downgrade of the Company's credit ratings may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:

- A severe prolonged economic downturn
- The bankruptcy of unrelated industry leaders in the same line of business
- Further deterioration in capital market conditions
- Turmoil in the financial services industry
- Volatility in commodity prices
- Terrorist attacks

Economic turmoil, market disruptions and volatility in the securities trading markets, as well as other factors including changes in the Company's financial condition, results of operations and prospects, may adversely affect the market price of the Company's common stock.

The Company currently has authorization to issue and sell up to $1.0 billion of securities pursuant to a registration statement on file with the SEC. The issuance of a substantial amount of the Company’s common stock, whether sold pursuant to the registration statement, issued in connection with an acquisition or otherwise issued, or the perception that such an issuance could occur, may adversely affect the market price of the Company’s common stock.

The Company is exposed to credit risk and the risk of loss resulting from the nonpayment and/or nonperformance by the Company's customers and counterparties.

If any of the Company's customers or counterparties were to experience financial difficulties or file for bankruptcy, the Company could experience difficulty in collection of receivables. The nonpayment and/or nonperformance by the Company's customers and counterparties could have a negative impact on the Company's results of operations and cash flows.

The backlog at the Company’s construction services and construction materials and contracting businesses is subject to delay or cancellation and may not be realized.

Backlog consists of the uncompleted portion of services to be performed under job-specific contracts. Contracts are subject to delay, default or cancellation and the contracts in our backlog are subject to changes in the scope of services to be provided as well as adjustments to the costs relating to the contract. Backlog may also be affected by project delays or cancellations resulting from weather conditions, external market factors and economic factors beyond our control, including the current economic slowdown. Accordingly, there is no assurance that backlog will be realized.

Environmental and Regulatory Risks
Some of the Company's operations are subject to extensive environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

The Company is subject to extensive environmental laws and regulations affecting many aspects of its present and future operations including air quality, water quality, waste management and other environmental considerations. These laws and regulations can result in increased capital, operating and other costs, and delays as a result of ongoing litigation and administrative proceedings and compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions and CBNG development. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Public officials and entities, as well as private individuals and organizations, may seek injunctive relief or other remedies to enforce applicable environmental laws and regulations. The Company cannot predict the outcome (financial or operational) of any related litigation or administrative proceedings that may arise.

Existing environmental laws and regulations may be revised and new laws and regulations seeking to protect the environment may be adopted or become applicable to the Company. These laws and regulations could require the Company to limit the use or output of certain facilities, restrict the use of certain fuels, require the installation of pollution control equipment or the initiation of pollution control technologies, remediate environmental contamination, remove or reduce environmental hazards, or prevent or limit the development of resources. Revised or additional laws and regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

The Company's electric generation operations could be adversely impacted by global climate change initiatives to reduce GHG emissions.

Concern that GHG emissions are contributing to global climate change has led to federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions including the EPA’s proposed endangerment finding for GHGs which could lead to regulation of GHG under the Clean Air Act. The primary GHG emitted from the Company's operations is carbon dioxide from combustion of fossil fuels at Montana-Dakota's electric generating facilities, particularly its coal-fired electric generating facilities which comprise more than 70 percent of Montana-Dakota’s generating capacity. More than 90 percent of the electricity generated by Montana-Dakota is from coal-fired plants and Montana-Dakota has acquired a 25 MW ownership interest in the Wygen III coal-fired generation facility which is under construction near Gillette, Wyoming and is a participant in the coal-fired Big Stone Station II project. Montana-Dakota also owns approximately 100 MW of natural gas- and oil-fired peaking plants. While there are many uncertainties regarding the future of GHG regulation, Montana-Dakota’s electric generating facilities are likely to be subject to regulation under climate change laws or regulations within the next few years. Implementation of legislation or regulations to reduce GHG emissions could affect Montana-Dakota's electric utility operations by requiring the expansion of energy conservation efforts and/or the increased development of renewable energy sources, as well as instituting other mandates that could significantly increase the capital expenditures and operating costs at its fossil fuel-fired generating facilities. The most prominent federal legislative proposals are based on “cap and trade” programs which place a limit on GHG emissions from major emission sources such as the electric generating industry. The impact of a cap and trade program on Montana-Dakota would be determined by considerations such as the overall GHG emissions cap level, the scope and timeframe by which the cap level is decreased, the extent to which GHG offsets are allowed, whether allowances are given to new and existing emission sources, and the indirect impact on natural gas, coal and other fuel prices. Montana-Dakota’s ability to recover costs incurred to comply with new regulations and programs will also be important in determining the financial impact on the Company.

Due to the uncertainty of technologies available to control GHG emissions and the unknown nature of compliance obligations with potential GHG emission legislation or regulations, the Company cannot determine the financial impact on its operations. If Montana-Dakota does not receive timely and full recovery of the costs of complying with GHG emission legislation and regulations from its customers, then such requirements could have an adverse impact on the results of its operations.

One of the Company's subsidiaries is subject to ongoing litigation and administrative proceedings in connection with its CBNG development activities. These proceedings have caused delays in CBNG drilling activity, and the ultimate outcome of the actions could have a material negative effect on existing CBNG operations and/or the future development of its CBNG properties.

Fidelity has been named as a defendant in, and/or certain of its operations are or have been the subject of, more than a half dozen lawsuits filed in connection with its CBNG development in the Powder River Basin in Montana and Wyoming. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material negative effect on Fidelity's existing CBNG operations and/or the future development of its CBNG properties.

The BER in March 2006 issued a decision in a rulemaking proceeding, initiated by the NPRC, that amends the non-degradation policy applicable to water discharged in connection with CBNG operations. The amended policy includes additional limitations on factors deemed harmful, thereby restricting water discharges even further than under previous standards. Due in part to this amended policy, in May 2006, the Northern Cheyenne Tribe commenced litigation in Montana state court challenging two five-year water discharge permits that the Montana DEQ granted to Fidelity in February 2006 and which are critical to Fidelity's ability to manage water produced under present and future CBNG operations. Although the Montana state court decided the case in favor of Fidelity and the Montana DEQ in January 2009, the case was appealed to the Montana Supreme Court in March 2009. If these permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

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

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
April 1 through April 30, 2009	---			
May 1 through May 31, 2009	44,550	$17.15		
June 1 through June 30, 2009	---			
Total	44,550			

(1) Represents shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors.

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

ITEM 6. EXHIBITS

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

SIGNATURES

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

MDU RESOURCES GROUP, INC.

DATE: August 7, 2009	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

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EXHIBIT INDEX

Exhibit No.	
+10(a)	Directors' Compensation Policy, as amended May 14, 2009
+10(b)	MDU Resources Group, Inc. 401(k) Retirement Plan, as restated June 1, 2009
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
101	The following materials from MDU Resources Group, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows and (iv) the Notes to Consolidated Financial Statements, tagged as blocks of text

+ 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.