MDU RESOURCES GROUP INC
Form 10-Q
August 06, 2010

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, 2010

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 30, 2010: 188,167,816 shares.

DEFINITIONS

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

Abbreviation or Acronym	
2009 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2009
ASC	FASB Accounting Standards Codification
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
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	Formerly proposed coal-fired electric generating facility located near Big Stone City, South Dakota (the Company had anticipated ownership of at least 116 MW)
Brazilian Transmission Lines	Company’s 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 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.
dk	Decatherm
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
GAAP	Accounting principles generally accepted in the United States of America

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GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
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
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBI	Morse Bros., Inc., an indirect wholly owned subsidiary of Knife River
MBOGC	Montana Board of Oil and Gas Conservation
Mcf	Thousand cubic feet
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
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
MEIC	Montana Environmental Information Center, Inc.
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 First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Twenty-Second Judicial District Court	Montana Twenty-Second Judicial District Court, Big Horn County
MPX	MPX Termoceara Ltda. (49 percent ownership, sold in June 2005)
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
North Dakota District Court	North Dakota South Central Judicial District Court for Burleigh County
NPRC	Northern Plains Resource Council
NSPS	New Source Performance Standards
Oil	Includes crude oil, condensate and natural gas liquids
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality

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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
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of natural gas and oil during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended
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
Wygen III	100-MW coal-fired electric generating facility located near Gillette, Wyoming (25 percent ownership)
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 Oregon and Washington. 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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$272,177	$263,617	$732,422	$858,191
Construction services, natural gas and oil production, construction materials and contracting, and other	634,267	694,423	1,008,799	1,193,854
Total operating revenues	906,444	958,040	1,741,221	2,052,045
Operating expenses:				
Fuel and purchased power	13,106	15,166	30,017	33,896
Purchased natural gas sold	97,441	106,401	331,133	462,897
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	68,437	62,581	131,421	133,932
Construction services, natural gas and oil production, construction materials and contracting, and other	516,854	554,556	830,642	976,706
Depreciation, depletion and amortization	81,547	80,449	160,225	173,694
Taxes, other than income	40,397	38,822	86,192	91,774
Write-down of natural gas and oil properties	—	—	—	620,000
Total operating expenses	817,782	857,975	1,569,630	2,492,899
Operating income (loss)	88,662	100,065	171,591	(440,854)
Earnings from equity method investments	2,260	2,078	4,443	3,864
Other income	2,686	2,435	5,188	4,154
Interest expense	20,490	20,759	41,006	41,755
Income (loss) before income taxes	73,118	83,819	140,216	(474,591)
Income taxes	24,180	28,508	49,506	(186,100)
Net income (loss)	48,938	55,311	90,710	(288,491)
Dividends on preferred stocks	171	171	343	343
Earnings (loss) on common stock	$48,767	$55,140	$90,367	$(288,834)
Earnings (loss) per common share -- basic	$.26	$.30	$.48	$(1.57)

Earnings (loss) per common share -- diluted	$.26	$.30	$.48	$(1.57)
Dividends per common share	$.1575	$.1550	$.3150	$.3100
Weighted average common shares outstanding -- basic	188,129	183,964	188,047	183,876
Weighted average common shares outstanding -- diluted	188,267	184,398	188,198	183,876

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

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

	June 30, 2010	June 30, 2009	December 31, 2009
	(In thousands, except shares and per share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$65,792	$34,310	$175,114
Receivables, net	502,454	559,842	531,980
Inventories	260,163	285,814	249,804
Deferred income taxes	17,755	2,490	28,145
Short-term investments	250	1,967	2,833
Commodity derivative instruments	24,932	62,048	7,761
Prepayments and other current assets	97,953	117,381	66,021
Total current assets	969,299	1,063,852	1,061,658
Investments	142,212	125,361	145,416
Property, plant and equipment	7,085,632	6,651,088	6,766,582
Less accumulated depreciation, depletion and amortization	3,000,663	2,906,824	2,872,465
Net property, plant and equipment	4,084,969	3,744,264	3,894,117
Deferred charges and other assets:			
Goodwill	634,654	622,131	629,463
Other intangible assets, net	26,199	25,320	28,977
Other	255,473	242,436	231,321
Total deferred charges and other assets	916,326	889,887	889,761
Total assets	$6,112,806	$5,823,364	$5,990,952
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Short-term borrowings	$3,700	$—	$10,300
Long-term debt due within one year	72,551	27,879	12,629
Accounts payable	266,069	332,957	281,906
Taxes payable	39,976	42,151	55,540
Dividends payable	29,802	28,686	29,749
Accrued compensation	35,989	44,141	47,425
Commodity derivative instruments	20,160	57,139	36,907
Other accrued liabilities	172,446	158,661	192,729
Total current liabilities	640,693	691,614	667,185
Long-term debt	1,508,714	1,636,592	1,486,677
Deferred credits and other liabilities:			
Deferred income taxes	627,256	540,952	590,968
Other liabilities	708,403	544,104	674,475
Total deferred credits and other liabilities	1,335,659	1,085,056	1,265,443
Commitments and contingencies			
Stockholders' equity:			
Preferred stocks	15,000	15,000	15,000
Common stockholders' equity:			
Common stock			

Shares issued -- $1.00 par value, 188,672,532 at June 30, 2010, 184,508,109 at June 30, 2009 and 188,389,265 at December 31, 2009	188,673	184,508	188,389
Other paid-in capital	1,020,206	941,773	1,015,678
Retained earnings	1,407,950	1,270,778	1,377,039
Accumulated other comprehensive income (loss)	(463)	1,669	(20,833)
Treasury stock at cost – 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,612,740	2,395,102	2,556,647
Total stockholders' equity	2,627,740	2,410,102	2,571,647
Total liabilities and stockholders' equity	$6,112,806	$5,823,364	$5,990,952

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

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

	Six Months Ended June 30,	
	2010	2009
	(In thousands)	
Operating activities:		
Net income (loss)	$90,710	$(288,491)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	160,225	173,694
Earnings, net of distributions, from equity method investments	(1,899)	(1,685)
Deferred income taxes	35,758	(206,955)
Write-down of natural gas and oil properties	—	620,000
Changes in current assets and liabilities, net of acquisitions:		
Receivables	27,149	149,782
Inventories	(12,442)	(26,574)
Other current assets	(32,471)	47,837
Accounts payable	(13,164)	(66,260)
Other current liabilities	(45,613)	2,218
Other noncurrent changes	(4,882)	(5,141)
Net cash provided by operating activities	203,371	398,425
Investing activities:		
Capital expenditures	(237,535)	(272,867)
Acquisitions, net of cash acquired	(106,548)	(3,764)
Net proceeds from sale or disposition of property	11,972	7,494
Investments	1,228	(2,368)
Net cash used in investing activities	(330,883)	(271,505)
Financing activities:		
Repayment of short-term borrowings	(6,600)	(105,100)
Issuance of long-term debt	82,992	109,400
Repayment of long-term debt	(814)	(92,024)
Proceeds from issuance of common stock	1,739	284
Dividends paid	(59,545)	(57,325)
Tax benefit on stock-based compensation	548	144
Net cash provided by (used in) financing activities	18,320	(144,621)
Effect of exchange rate changes on cash and cash equivalents	(130)	297
Decrease in cash and cash equivalents	(109,322)	(17,404)
Cash and cash equivalents -- beginning of year	175,114	51,714
Cash and cash equivalents -- end of period	$65,792	$34,310

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

June 30, 2010 and 2009
(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 2009 Annual Report, and the standards of accounting measurement set forth in the interim reporting guidance in the ASC 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 2009 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. Management has also evaluated the impact of events occurring after June 30, 2010, up to the date of issuance of these consolidated interim financial statements.

2. Seasonality of operations

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

3. Allowance for doubtful accounts

The Company's allowance for doubtful accounts as of June 30, 2010 and 2009, and December 31, 2009, was $14.9 million, $16.5 million and $16.6 million, respectively.

4. Natural gas in storage

Natural gas in storage for the Company's regulated operations is generally carried at average cost, or 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 $14.3 million, $19.1 million and $35.6 million at June 30, 2010 and 2009, and December 31, 2009, 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 $59.3 million, $40.3 million, and $59.6 million at June 30, 2010 and 2009, and December 31, 2009, respectively.

5. Inventories

Inventories, other than natural gas in storage for the Company’s regulated operations, consisted primarily of aggregates held for resale of $83.5 million, $96.3 million and $80.1 million; materials and supplies of $62.1 million, $69.4 million and $58.1 million; asphalt oil of $52.0 million, $49.8 million and $23.0 million; and other inventories of $48.3 million, $51.2 million and $53.0 million, as of June 30, 2010 and 2009, and December 31, 2009, 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 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 was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. Prior to that date, if capitalized costs exceeded the full-cost ceiling at the end of any quarter, a permanent noncash write-down was required to be charged to earnings in that quarter unless subsequent price changes eliminated or reduced an indicated write-down. Effective December 31, 2009, 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 regardless of subsequent price changes.

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.

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) at 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.

At June 30, 2010, 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, 2010, could result in a future write-down of the Company’s natural gas and oil properties.

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, 2010 and 2009, and the six months ended June 30, 2010, 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, 2010	2009
	(In thousands)	
Interest, net of amount capitalized	$ 39,652	$ 40,588
Income taxes	$ 36,011	$ 13,343

9. New accounting standards

Variable Interest Entities In June 2009, the FASB issued guidance related to variable interest entities which 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. This guidance requires 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. The guidance related to variable interest entities was effective for the Company on January 1, 2010. The adoption of this guidance did not have a material effect on the Company's financial position or results of operations.

Improving Disclosure About Fair Value Measurements In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods and were effective for the Company on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. The guidance requires additional disclosures but does not impact the Company's financial position or results of operations.

Subsequent Events In February 2010, the FASB issued guidance amending certain recognition and disclosure requirements related to subsequent events. The guidance requires an entity that is an SEC filer to evaluate subsequent events through the date that the financial statements are issued. The guidance also removes the requirement to disclose the date through which subsequent events were evaluated. The guidance related to subsequent events was effective for the Company in the first quarter of 2010. The adoption of this guidance did not impact the Company's financial position or results of operations.

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 income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges and foreign currency translation adjustments. For more information on derivative instruments, see Note 13.

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

	Three Months Ended June 30,	
	2010	2009
	(In thousands)	
Net income	$ 48,938	$ 55,311
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 $2,588 and $(4,028) in 2010 and 2009, respectively	4,637	(6,571)
Less: Reclassification adjustment for gain on derivative instruments included in net income, net of tax of $3,191 and $11,415 in 2010 and 2009, respectively	5,259	18,625
Net unrealized loss on derivative instruments qualifying as hedges	(622)	(25,196)
Foreign currency translation adjustment, net of tax of $307 and $3,711 in 2010 and 2009, respectively	(476)	5,756
	(1,098)	(19,440)
Comprehensive income	$ 47,840	$ 35,871

	Six Months Ended June 30,	
	2010	2009
	(In thousands)	
Net income (loss)	$ 90,710	$ (288,491)
Other comprehensive income (loss):		
Net unrealized gain (loss) on derivative instruments qualifying as hedges:		
Net unrealized gain on derivative instruments arising during the period, net of tax of $11,962 and $5,634 in 2010 and 2009, respectively	19,932	9,193
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income (loss), net of tax of $(1,166) and $14,646 in 2010 and 2009, respectively	(1,850)	23,896
Net unrealized gain (loss) on derivative instruments qualifying as hedges	21,782	(14,703)
Foreign currency translation adjustment, net of tax of $(929) and $3,875 in 2010 and 2009, respectively	(1,412)	6,007
	20,370	(8,696)
Comprehensive income (loss)	$ 111,080	$ (297,187)

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, 2010, include the Brazilian Transmission Lines.

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

In the fourth quarter of 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. Regulatory approval for the sale has been received. The financial closing of the sale is anticipated to occur later this year. One of the parties will purchase 15.6 percent of the Company’s ownership interests over a four-year period. The other parties will purchase 84.4 percent of the Company’s ownership interests at the financial close of the transaction.

At June 30, 2010 and 2009, and December 31, 2009, the Company's equity method investments had total assets of $369.9 million, $348.3 million and $387.0 million, respectively, and long-term debt of $157.1 million, $171.7 million and $176.7 million, respectively. The Company's investment in its equity method investments was approximately $57.9 million, $52.6 million and $62.4 million, including undistributed earnings of $11.1 million, $8.4 million and $9.3 million, at June 30, 2010 and 2009, and December 31, 2009, respectively.

12. Goodwill and other intangible assets

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

Six Months Ended June 30, 2010	Balance as of January 1, 2010	Goodwill Acquired During the Year* (In thousands)	Balance as of June 30, 2010
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Construction services	100,127	2,764	102,891
Pipeline and energy services	7,857	1,880	9,737
Natural gas and oil production	—	—	—
Construction materials and contracting	175,743	547	176,290
Other	—	—	—
Total	$ 629,463	$ 5,191	$ 634,654

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

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.

Year Ended December 31, 2009	Balance as of January 1, 2009	Goodwill Acquired During the Year*	Balance as of December 31, 2009
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	344,952	784	345,736
Construction services	95,619	4,508	100,127
Pipeline and energy services	1,159	6,698	7,857
Natural gas and oil production	—	—	—
Construction materials and contracting	174,005	1,738	175,743
Other	—	—	—
Total	$ 615,735	$ 13,728	$ 629,463

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

Other intangible assets were as follows:

	June 30, 2010	June 30, 2009	December 31, 2009
		(In thousands)	
Customer relationships	$ 24,942	$ 21,688	$ 24,942
Accumulated amortization	(10,688)	(8,142)	(9,500)
	14,254	13,546	15,442
Noncompete agreements	9,405	9,792	12,377
Accumulated amortization	(6,033)	(5,942)	(6,675)
	3,372	3,850	5,702
Other	12,063	10,679	10,859
Accumulated amortization	(3,490)	(2,755)	(3,026)
	8,573	7,924	7,833
Total	$ 26,199	$ 25,320	$ 28,977

Amortization expense for amortizable intangible assets for the three and six months ended June 30, 2010, was $1.1 million and $2.1 million, respectively. Amortization expense for the three and six months ended June 30, 2009, was $1.2 million and $2.6 million, respectively. Estimated amortization expense for amortizable intangible assets is $4.2 million in 2010, $3.9 million in 2011, $3.8 million in 2012, $3.3 million in 2013, $2.9 million in 2014 and $10.2 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, 2010, 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 2009 Annual Report.

Cascade and Intermountain

At June 30, 2010, Cascade and Intermountain held natural gas swap agreements, with total forward notional volumes of 9.2 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 portfolios 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 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, 2010, Cascade and Intermountain recorded the change in the fair market value of the derivative instruments of $3.9 million and $9.0 million, respectively, as a decrease to 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, 2010, was $18.9 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, 2010, was $18.9 million.

Fidelity

At June 30, 2010, Fidelity held natural gas swaps and collar agreements with total forward notional volumes of 27.1 million MMBtu, natural gas basis swaps with total forward notional volumes of 17.3 million MMBtu, and oil swap and collar agreements with total forward notional volumes of 2.0 million Bbl, which were designated as cash flow hedging instruments. 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.

For the three and six months ended June 30, 2010, and 2009, the amount of hedge ineffectiveness was immaterial, 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.

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 (loss) and the gains and losses reclassified from accumulated other comprehensive income (loss) into earnings, see Note 10.

As of June 30, 2010, 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 $14.3 million (after tax) will be reclassified from accumulated other comprehensive income (loss) 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, 2010, was $2.0 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, 2010, was $2.0 million.

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

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at June 30, 2010	Fair Value at June 30, 2009	Fair Value at December 31, 2009
			(In thousands)	
Designated as hedges	Commodity derivative instruments	$ 24,932	$ 62,047	$ 7,761
	Other assets – noncurrent	8,524	4,217	2,734
		33,456	66,264	10,495
Not designated as hedges	Commodity derivative instruments	—	1	—
	Other assets – noncurrent	—	1	—
		—	2	—
Total asset derivatives		$ 33,456	$ 66,266	$ 10,495

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at June 30, 2010	Fair Value at June 30, 2009	Fair Value at December 31, 2009
			(In thousands)	
Designated as hedges	Commodity derivative instruments	$ 1,961	$ 8,440	$ 13,763
	Other liabilities – noncurrent	—	1,538	114
		1,961	9,978	13,877
Not designated as hedges	Commodity derivative instruments	18,199	48,699	23,144
	Other liabilities – noncurrent	698	10,786	4,756
		18,897	59,485	27,900
Total liability derivatives		$ 20,858	$ 69,463	$ 41,777

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 at June 30, 2009.

14. Fair value measurements

The Company elected to measure its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. 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 $20.2 million, $29.5 million and $34.8 million, as of June 30, 2010 and 2009, and December 31, 2009, respectively, are classified as Investments on the Consolidated Balance Sheets. The decrease in the fair value of these investments for the three and six months ended June 30, 2010, was $1.8 million (before tax) and $970,000 (before tax), respectively. 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 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, 2010 and 2009, and December 31, 2009, are accounted for as available-for-sale 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.

Fair value is defined 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 ASC 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, 2010, 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, 2010
			(In thousands)		
Assets:					
Money market funds	$8,251	$—	$ —	$ —	$8,251
Available-for-sale securities:					
Fixed-income securities	—	11,400	—	—	11,400
Insurance contract*	—	20,236	—	—	20,236
Commodity derivative instruments - current	—	24,932	—	—	24,932
Commodity derivative instruments - noncurrent	—	8,524	—	—	8,524
Total assets measured at fair value	$8,251	$65,092	$ —	$ —	$73,343
Liabilities:					
Commodity derivative instruments - current	$—	$20,160	$ —	$ —	$20,160
Commodity derivative instruments - noncurrent	—	698	—	—	698
Total liabilities measured at fair value	$—	$20,858	$ —	$ —	$20,858

* Invested in mutual funds.

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	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 December 31, 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 December 31, 2009
			(In thousands)		
Assets:					
Money market funds	$9,124	$151,000	$ —	$ —	$ 160,124
Available-for-sale securities	9,078	37,141	—	—	46,219
Commodity derivative instruments - current	—	7,761	—	—	7,761
Commodity derivative instruments - noncurrent	—	2,734	—	—	2,734
Total assets measured at fair value	$18,202	$198,636	$ —	$ —	$ 216,838
Liabilities:					
Commodity derivative instruments - current	$—	$36,907	$ —	$ —	$ 36,907
Commodity derivative instruments - noncurrent	—	4,870	—	—	4,870
Total liabilities measured at fair value	$—	$41,777	$ —	$ —	$ 41,777

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The estimated fair value of the Company's Level 1 money market funds is determined using the market approach and is valued at the net asset value of shares held by the Company, based on published market quotations in active markets.

The estimated fair value of the Company's Level 1 available-for-sale securities is determined using the market approach and 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 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. 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 Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The nonperformance risk of the counterparties in addition to the Company's nonperformance risk is also evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value.

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 was as follows:

	Carrying Amount	Fair Value
	(In thousands)	
Long-term debt at June 30, 2010	$ 1,581,265	$ 1,718,477
Long-term debt at June 30, 2009	$ 1,664,471	$ 1,538,693
Long-term debt at December 31, 2009	$ 1,499,306	$ 1,566,331

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 suppression 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 cathodic protection and other energy-related 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 2009 Annual Report. Information on the Company's businesses was as follows:

Three Months Ended June 30, 2010	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 45,683	$ —	$ 4,947
Natural gas distribution	160,138	—	74
Pipeline and energy services	66,356	14,143	9,541
	272,177	14,143	14,562
Construction services	188,182	8	2,923
Natural gas and oil production	84,406	26,400	24,035
Construction materials and contracting	361,625	—	5,659
Other	54	2,213	1,588
	634,267	28,621	34,205
Intersegment eliminations	—	(42,764)	—
Total	$ 906,444	$ —	$ 48,767

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

Six Months Ended June 30, 2010	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 95,379	$ —	$ 10,832
Natural gas distribution	509,162	—	23,416
Pipeline and energy services	127,881	41,228	18,332
	732,422	41,228	52,580
Construction services	341,247	32	3,051
Natural gas and oil production	156,066	62,327	46,246
Construction materials and contracting	511,432	—	(14,478)
Other	54	4,451	2,968
	1,008,799	66,810	37,787
Intersegment eliminations	—	(108,038)	—
Total	$ 1,741,221	$ —	$ 90,367

Six Months Ended June 30, 2009	External Operating Revenues	Inter-segment Operating Revenues	Earnings (Loss) on Common Stock
		(In thousands)	
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)

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. Acquisitions

During the first six months of 2010, the Company acquired natural gas properties located in the Green River Basin in southwest Wyoming, with an October 1, 2009, effective date. The acquisition includes the purchase of over 60 Bcfe of proven reserves. The total purchase consideration for these properties and purchase price adjustments with respect to acquisitions made prior to 2010, consisting of the Company’s common stock and cash, was approximately $108.1 million.

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

17. Employee benefit plans

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

Three Months Ended June 30,	Pension Benefits 2010	Pension Benefits 2009	Other Postretirement Benefits 2010	Other Postretirement Benefits 2009
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 501	$ 1,966	$ 374	$ 651
Interest cost	4,004	5,430	1,317	1,530
Expected return on assets	(4,992)	(5,673)	(1,577)	(1,544)
Amortization of prior service cost (credit)	31	151	(915)	(810)
Amortization of net actuarial loss	256	643	67	170
Amortization of net transition obligation	—	—	613	625
Net periodic benefit cost, including amount capitalized	(200)	2,517	(121)	622
Less amount capitalized	107	484	37	(23)
Net periodic benefit cost	$ (307)	$ 2,033	$ (158)	$ 645

Six Months Ended June 30,	Pension Benefits 2010	Pension Benefits 2009	Other Postretirement Benefits 2010	Other Postretirement Benefits 2009
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 1,305	$ 4,063	$ 731	$ 1,091
Interest cost	8,930	10,959	2,594	2,725
Expected return on assets	(10,684)	(12,530)	(2,969)	(2,817)
Amortization of prior service cost (credit)	69	302	(1,779)	(1,378)
Amortization of net actuarial loss	1,228	817	455	355
Amortization of net transition obligation	—	—	1,145	1,063
Net periodic benefit cost, including amount capitalized	848	3,611	177	1,039

Less amount capitalized	383	765	84	23
Net periodic benefit cost	$ 465	$ 2,846	$ 93	$ 1,016

In 2009, the Company evaluated several provisions of its employee defined benefit plans for nonunion and certain union employees. As a result of this evaluation, the Company determined that, effective January 1, 2010, all benefit and service accruals of these plans were frozen. These employees are eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Current employees who attain age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, are not eligible for retiree medical benefits.

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, 2010, was $1.7 million and $3.8 million, respectively. 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.

18. Regulatory matters and revenues subject to refund

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. The intervenors in the proceeding appealed the NDPSC order to the North Dakota District Court which affirmed the order of the NDPSC. The intervenors then appealed the North Dakota District Court order to the North Dakota Supreme Court. The Big Stone Station II participants subsequently decided not to proceed with the project and in December 2009, Montana-Dakota filed an application with the NDPSC for a determination that Montana-Dakota's continued participation in the Big Stone Station II is no longer prudent. In December 2009, Montana-Dakota filed applications with the NDPSC, SDPUC, and MTPSC for authority to defer the costs incurred for securing new electric generation, primarily Big Stone Station II, until the next general rate case. The SDPUC and the MTPSC approved Montana-Dakota's applications on February 11, 2010, and April 6, 2010, respectively. On April 14, 2010, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC. The settlement agreement provides for the recovery of the North Dakota allocated costs associated with the Big Stone Station II over a three-year period beginning June 1, 2010, with carrying charges applicable to the balance at the authorized rate of return until recovery commences. On June 25, 2010, the NDPSC approved the settlement agreement, with a modification to the carrying charge rate, to be effective with service rendered August 1, 2010. On July 7, 2010, Montana-Dakota filed a compliance filing on the June 25, 2010, order. On June 28, 2010, the North Dakota Supreme Court dismissed the appeal of the intervenors pursuant to a stipulation of voluntary dismissal by the parties.

In August 2009, Montana-Dakota filed an application with the WYPSC for an electric rate increase. Montana-Dakota requested a total increase of $6.2 million annually or approximately 31 percent above current rates. The rate increase request was necessitated by Montana-Dakota’s purchase of an ownership interest in Wygen III. On January 14, 2010, Montana-Dakota filed a supplement to the application to reflect the inclusion of bonus tax depreciation on Wygen III, reducing its request to a $5.1 million annual increase or approximately 25 percent above current rates. A hearing was held February 23 through February 25, 2010. A stipulation and agreement between Montana-Dakota and the Wyoming Office of Consumer Advocate was filed with the WYPSC on March 5, 2010, that provides a $3.3 million annual increase to be phased-in over a three-year period beginning May 1, 2010. The WYPSC held a hearing on the stipulation on March 22, 2010, and held additional deliberations on April 14, 2010, wherein the WYPSC decided on each issue in the case and Montana-Dakota was directed to file a compliance filing. Montana-Dakota submitted the compliance filing on April 23, 2010, reflecting an increase of $2.7 million annually or approximately 13.1 percent. On April 27, 2010, the WYPSC approved the compliance filing with rates effective May 1, 2010. On June 25, 2010, Montana-Dakota filed a Petition for Rehearing on the return on equity specified in the WYPSC’s order. On July 14, 2010, the WYPSC held oral arguments and denied Montana-Dakota’s request.

On April 19, 2010, Montana-Dakota filed an application with the NDPSC for an electric rate increase. Montana-Dakota requested a total increase of $15.4 million annually or approximately 14 percent above current rates. The requested increase includes the investment in infrastructure upgrades, recovery of the investment in renewable generation and the costs associated with Big Stone Station II. On June 16, 2010, the NDPSC approved an interim increase of $7.6 million effective with service rendered June 18, 2010. On June 16, 2010, Montana-Dakota and the NDPSC Advocacy Staff filed a partial settlement agreement agreeing to an overall rate of return and a sharing of earnings over a specified return on equity. On July 6, 2010, Montana-Dakota filed an amendment to its application to exclude the deferred generation development costs associated with Big Stone Station II because of a settlement agreement approved by the NDPSC that provided for recovery of such development costs. Montana-Dakota’s amended request is an increase of $13.3 million annually or 12 percent. A hearing has been set for November 8, 2010.

19. Contingencies

Litigation

Coalbed Natural Gas Operations Fidelity’s CBNG operations are and have been the subject of numerous lawsuits in Montana and Wyoming. The current cases involve the permitting and use of water produced in connection with Fidelity’s CBNG development in the Powder River Basin. Some of these cases challenge the issuance of discharge permits by the Montana DEQ and approval of other water management tools by the MBOGC.

In April 2006, the Northern Cheyenne Tribe filed a complaint in Montana Twenty-Second Judicial District Court against the Montana DEQ seeking to set aside Fidelity's 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. In January 2009, the Montana Twenty-Second Judicial 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 continued 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 in March 2009. On May 18, 2010, the Montana Supreme Court reversed the Montana Twenty-Second Judicial District Court's decision and held that the Montana DEQ violated the Clean Water Act and the Montana Water Quality Act by issuing discharge permits to Fidelity without imposing predischarge treatment standards. The Montana Supreme Court declared Fidelity's permits void and directed the Montana DEQ to reevaluate Fidelity's permit applications under the appropriate predischarge treatment standards within 90 days of the Court's decision, during which time Fidelity may continue to operate under its current permits. On June 2, 2010, Fidelity filed a motion with the Montana Supreme Court requesting the court to allow the Montana DEQ an additional 90 days to complete its reevaluation of Fidelity's discharge permits. On June 29, 2010, the Montana Supreme Court granted a one-time extension allowing the Montana DEQ until November 14, 2010, to complete the permitting process.

Fidelity's discharge of water pursuant to its two permits is its primary means for managing CBNG-produced water. Fidelity will not be able to assess the impact to its operations until the Montana DEQ issues final permits.

In October 2003, Tongue & Yellowstone Irrigation District, NPRC and MEIC filed a lawsuit in Montana First Judicial District Court challenging the MBOGC's ROD adopting the 2003 Final EIS which analyzed CBNG development in Montana. The primary legal issue before the court was whether the ROD authorized the "wasting" of ground water in violation of the Montana State Constitution and the public trust doctrine. Specifically, the plaintiffs contended that various water management tools, including Fidelity's direct discharge permits, allowed for the waste of water. On March 5, 2010, the Montana First Judicial District Court issued an order holding that Fidelity's direct discharge permits did not violate the Montana State Constitution. Once judgment is entered, the parties will have 60 days to appeal to the Montana Supreme Court. Should the Montana Supreme Court determine the permits violate the Montana State Constitution, Fidelity's Montana CBNG operations could be significantly and adversely affected.

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. In March 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. The United States has filed a brief as amicus curiae supporting the Sierra Club’s position in the appeal and the State of South Dakota filed a brief as amicus curiae supporting the Big Stone Station owners’ position in the appeal. Oral argument on the appeal was held on May 11, 2010.

Construction Materials LTM is a defendant in litigation pending in Oregon Circuit Court regarding the concrete floors in an industrial food processing facility located in Jackson County, Oregon. The plaintiffs assert claims against LTM, which supplied the concrete for the floors, and others that 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 plaintiffs to be approximately $26.5 million. Discovery is currently being conducted by the parties. A trial date has been scheduled for April 5, 2011.

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 in March 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 requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. Cascade received notice in April 2010, that the Washington Department of Ecology has determined that Cascade is a PRP for release of hazardous substances at the site. Cascade has reserved $6.4 million for remediation of this site. On April 9, 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case.

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 and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. 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. In February 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. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand seeks compensatory damages of $146 million plus damages for increased operating, capital and construction costs related to a water treatment facility for the generating facility. LPP’s notice of demand for arbitration also demanded performance of the guarantee by Centennial. In June 2010, CEM and Bicent Power, LLC made a demand on Centennial for indemnification under the 2007 purchase and sale agreement for indemnifiable losses, including defense fees and costs of more than $1.5 million, arising from LPP’s arbitration demand and related to Centennial’s ownership of CEM prior to its sale from Centennial to Bicent Power, LLC. The Company believes the indemnification claims against Centennial are without merit and intends to vigorously defend against such claims.

In connection with the pending sale of the Brazilian Transmission Lines, as discussed in Note 11, Centennial has agreed to unconditionally guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the pending sale of the Brazilian Transmission Lines.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil 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 swap and collar agreements at June 30, 2010, expire in the years ranging from 2010 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 were no amounts outstanding by Fidelity at June 30, 2010. 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, 2010, the fixed maximum amounts guaranteed under these agreements aggregated $224.5 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $4.3 million in 2010; $191.8 million in 2011; $18.7 million in 2012; $1.2 million in 2013; $200,000 in 2014; $900,000 in 2018; $300,000 in 2019; $3.1 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, 2010. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, natural gas transportation agreements and other agreements that guarantee the performance of other subsidiaries of the Company. At June 30, 2010, the fixed maximum amounts guaranteed under these letters of credit, aggregated $29.1 million. In 2010 and 2011, $22.2 million and $6.9 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at June 30, 2010.

WBI Holdings has an outstanding guarantee to Williston Basin. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At June 30, 2010, the fixed maximum amount guaranteed under this agreement aggregated $5.0 million and is scheduled to expire in 2011. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.4 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at June 30, 2010, because this intercompany transaction was 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, 2010.

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, 2010, approximately $646 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

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

OVERVIEW

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

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

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities and the issuance from time to time of debt and equity securities. In the event that access to the commercial paper markets were to become unavailable, the Company may need to borrow under its credit agreements. 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 and related services to customers. 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 with a diverse resource mix that includes renewable generation, and transmission 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. The ability of these segments to grow through acquisitions is subject to significant competition. 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 may be 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. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas.

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; expansion of related energy services; 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 both in new and existing 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 permitted aggregate reserves being significant. A key element of the Company's long-term

strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

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

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 2009 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,	
	2010	2009	2010	2009
	(Dollars in millions, where applicable)			
Electric	$5.0	$3.2	$10.8	$8.3
Natural gas distribution	.1	(4.8)	23.4	19.1
Construction services	2.9	6.9	3.1	15.6
Pipeline and energy services	9.5	10.9	18.3	17.3
Natural gas and oil production	24.0	20.8	46.3	(352.5)
Construction materials and contracting	5.7	16.0	(14.5)	.3
Other	1.6	2.1	3.0	3.1
Earnings (loss) on common stock	$48.8	$55.1	$90.4	$(288.8)
Earnings (loss) per common share – basic	$.26	$.30	$.48	$(1.57)
Earnings (loss) per common share – diluted	$.26	$.30	$.48	$(1.57)
Return on average common equity for the 12 months ended			10.0%	(6.9)%

Three Months Ended June 30, 2010 and 2009 Consolidated earnings for the quarter ended June 30, 2010, decreased $6.3 million from the comparable prior period largely due to:

- Lower aggregate, ready-mixed concrete and liquid asphalt oil volumes and margins, as well as decreased construction and asphalt margins, partially offset by lower depreciation, depletion and amortization expense at the construction materials and contracting business
- Lower construction workloads and margins, partially offset by lower general and administrative expense at the construction services business

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Partially offsetting these decreases were:

- Increased retail sales and transportation volumes, lower operation and maintenance expense, as well as higher nonregulated energy-related services at the natural gas distribution business
- Higher average realized oil prices, increased oil production, lower general and administrative and lease operating expenses, partially offset by lower average realized gas prices, decreased natural gas production, higher production taxes, as well as higher depreciation, depletion and amortization expense at the natural gas and oil production business

Six Months Ended June 30, 2010 and 2009 Consolidated earnings for the six months ended June 30, 2010, increased $379.2 million primarily due to:

- Absence of the 2009 noncash write-down of natural gas and oil properties of $384.4 million (after tax), higher average realized oil prices, lower depreciation, depletion and amortization expense, lower lease operating expenses, increased oil production, as well as lower general and administrative expense, partially offset by decreased natural gas production, lower average realized natural gas prices and higher production taxes at the natural gas and oil production business
- Lower operation and maintenance expense, lower interest expense and higher other income at the natural gas distribution business

Partially offsetting these increases were:

- Lower aggregate, ready-mixed concrete and liquid asphalt oil volumes and margins, as well as decreased construction and asphalt margins, partially offset by lower depreciation, depletion and amortization expense and lower selling, general and administrative expense at the construction materials and contracting business
- Lower construction workloads and margins, partially offset by lower general and administrative expense at the construction services business

FINANCIAL AND OPERATING DATA

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

Electric

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(Dollars in millions, where applicable)			
Operating revenues	$45.7	$44.5	$95.4	$95.8
Operating expenses:				
Fuel and purchased power	13.1	15.2	30.0	33.9
Operation and maintenance	16.2	15.9	31.4	31.5
Depreciation, depletion and amortization	6.1	6.0	11.9	12.2
Taxes, other than income	2.2	2.3	4.8	4.7
	37.6	39.4	78.1	82.3
Operating income	8.1	5.1	17.3	13.5
Earnings	$5.0	$3.2	$10.8	$8.3
Retail sales (million kWh)	615.2	595.3	1,365.0	1,320.1
Sales for resale (million kWh)	7.6	22.8	37.4	32.5
Average cost of fuel and purchased power per kWh	$.020	$.023	$.020	$.024

Three Months Ended June 30, 2010 and 2009 Electric earnings increased $1.8 million (52 percent) due to:

- Higher electric retail sales margins, primarily due to the implementation of higher rates in Wyoming
- Higher retail sales volumes of 3 percent, primarily to commercial and residential customers

Six Months Ended June 30, 2010 and 2009 Electric earnings increased $2.5 million (30 percent) due to:

- Increased retail sales margins and volumes of $2.1 million (after tax), as previously discussed
- Higher other income of $900,000 (after tax), primarily allowance for funds used during construction related to electric generation projects

Partially offsetting these increases was higher interest expense, resulting from higher average borrowings.

Natural Gas Distribution

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(Dollars in millions, where applicable)			
Operating revenues	$160.1	$164.1	$509.2	$647.3
Operating expenses:				
Purchased natural gas sold	98.9	107.5	344.1	473.5
Operation and maintenance	34.4	35.5	67.1	73.6
Depreciation, depletion and amortization	10.7	10.6	21.4	21.3
Taxes, other than income	10.5	11.3	27.0	34.2
	154.5	164.9	459.6	602.6
Operating income (loss)	5.6	(.8)	49.6	44.7
Earnings (loss)	$.1	$(4.8)	$23.4	$19.1
Volumes (MMdk):				
Sales	15.6	14.1	53.7	57.7
Transportation	28.9	23.4	63.4	57.4
Total throughput	44.5	37.5	117.1	115.1
Degree days (% of normal)*				
Montana-Dakota	96%	119%	98%	106%
Cascade	118%	100%	95%	105%
Intermountain	132%	103%	103%	105%
Average cost of natural gas, including transportation, per dk	$6.33	$7.61	$6.41	$8.20

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

Three Months Ended June 30, 2010 and 2009 Earnings at the natural gas distribution business increased $4.9 million compared to the prior year due to:

- Increased retail sales volumes, largely resulting from colder weather than last year in the Northwest
- Lower operation and maintenance expense, largely lower bad debt expense and benefit-related costs
- Increased transportation volumes of $500,000 (after tax), primarily industrial customers
- Higher nonregulated energy-related services of $400,000 (after tax)

Six Months Ended June 30, 2010 and 2009 Earnings at the natural gas distribution business increased $4.3 million (23 percent) due to:

- Lower operation and maintenance expense of $3.2 million (after tax), largely lower payroll and benefit-related costs and bad debt expense
- Lower interest expense, primarily due to lower average borrowings and higher capitalized interest
- Higher other income of $600,000 (after tax), primarily allowance for funds used during construction

Construction Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Operating revenues	$188.2	$220.7	$341.3	$465.5
Operating expenses:				
Operation and maintenance	173.2	199.2	315.0	416.4
Depreciation, depletion and amortization	3.1	3.3	6.3	6.7
Taxes, other than income	6.1	6.4	12.6	16.0
	182.4	208.9	333.9	439.1
Operating income	5.8	11.8	7.4	26.4
Earnings	$2.9	$6.9	$3.1	$15.6

Three Months Ended June 30, 2010 and 2009 Construction services earnings decreased $4.0 million (58 percent) due to lower construction workloads and margins, primarily in the Southwest region, partially offset by lower general and administrative expense of $3.5 million (after tax), largely payroll-related.

Six Months Ended June 30, 2010 and 2009 Construction services earnings decreased $12.5 million (80 percent) due to lower construction workloads and margins, primarily in the Southwest region, partially offset by lower general and administrative expense of $6.6 million (after tax), largely payroll-related.

Pipeline and Energy Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(Dollars in millions)			
Operating revenues	$80.5	$68.0	$169.1	$153.1
Operating expenses:				
Purchased natural gas sold	35.3	28.1	82.8	74.2
Operation and maintenance	17.8	11.1	33.0	28.8
Depreciation, depletion and amortization	6.5	6.2	12.9	12.3
Taxes, other than income	3.2	3.0	6.2	5.9
	62.8	48.4	134.9	121.2
Operating income	17.7	19.6	34.2	31.9
Earnings	$9.5	$10.9	$18.3	$17.3
Transportation volumes (MMdk):				
Montana-Dakota	7.3	10.2	14.9	18.5
Other	37.0	33.6	59.9	62.4
	44.3	43.8	74.8	80.9
Gathering volumes (MMdk)	19.3	24.3	38.4	48.6

Three Months Ended June 30, 2010 and 2009 Pipeline and energy services earnings decreased $1.4 million (12 percent) due to:

- Higher operation and maintenance expense of $3.1 million (after tax), primarily due to the absence of the settlement of the natural gas storage litigation, which lowered expense in the second quarter last year
- Lower gathering volumes of $1.2 million (after tax)

Partially offsetting the earnings decrease were higher storage services revenue of $1.9 million (after tax), as well as higher volumes transported to storage.

Six Months Ended June 30, 2010 and 2009 Pipeline and energy services earnings increased $1.0 million (6 percent) due to higher storage services revenue of $4.3 million (after tax), largely higher storage balances.

Partially offsetting this increase were:

- Lower gathering volumes of $2.7 million (after tax)
- Higher operation and maintenance expense of $1.0 million (after tax), including higher payroll-related costs

Natural Gas and Oil Production

	Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
	(Dollars in millions, where applicable)			
Operating revenues:				
Natural gas	$55.2	$69.2	$112.8	$150.9
Oil	55.6	35.6	105.6	60.0
	110.8	104.8	218.4	210.9
Operating expenses:				
Operation and maintenance:				
Lease operating costs	16.3	18.0	32.1	38.0
Gathering and transportation	5.9	6.1	11.8	12.2
Other	8.8	10.7	17.4	21.0
Depreciation, depletion and amortization	32.5	30.2	62.1	72.8
Taxes, other than income:				
Production and property taxes	9.0	5.7	18.5	13.2
Other	.1	.2	.5	.4
Write-down of natural gas and oil properties	—	—	—	620.0
	72.6	70.9	142.4	777.6
Operating income (loss)	38.2	33.9	76.0	(566.7)
Earnings (loss)	$24.0	$20.8	$46.3	$(352.5)
Production:				
Natural gas (MMcf)	12,809	14,297	25,052	29,698
Oil (MBbls)	831	771	1,592	1,513
Total Production (MMcf equivalent)	17,794	18,923	34,602	38,775
Average realized prices (including hedges):				
Natural gas (per Mcf)	$4.31	$4.84	$4.50	$5.08
Oil (per barrel)	$66.88	$46.21	$66.36	$39.67
Average realized prices (excluding hedges):				
Natural gas (per Mcf)	$3.30	$2.40	$3.92	$3.04
Oil (per barrel)	$67.21	$47.46	$66.83	$40.30
Average depreciation, depletion and amortization rate, per equivalent Mcf	$1.74	$1.52	$1.71	$1.80
Production costs, including taxes, per net equivalent Mcf:				
Lease operating costs	$.91	$.95	$.93	$.98
Gathering and transportation	.33	.32	.34	.31
Production and property taxes	.51	.30	.53	.34
	$1.75	$1.57	$1.80	$1.63

Three Months Ended June 30, 2010 and 2009 Natural gas and oil production earnings increased $3.2 million (16 percent) due to:

- Higher average realized oil prices of 45 percent
- Increased oil production of 8 percent, largely related to drilling activity in the Bakken area
- Lower general and administrative expense of $1.3 million (after tax)
- Decreased lease operating expenses of $1.1 million (after tax)

Partially offsetting these increases were:

- Lower average realized natural gas prices of 11 percent
- Decreased natural gas production of 10 percent, largely related to normal production declines at existing properties, partially offset by production from the recently acquired Green River Basin properties
- Higher production taxes of $1.9 million (after tax)
- Higher depreciation, depletion and amortization expense of $1.4 million (after tax), due to higher depletion rates

Six Months Ended June 30, 2010 and 2009 Natural gas and oil production earnings increased $398.8 million due to:

- Absence of the 2009 noncash write-down of natural gas and oil properties of $384.4 million (after tax), as discussed in Note 6
- Higher average realized oil prices of 67 percent
- Lower depreciation, depletion and amortization expense of $6.6 million (after tax), due to lower depletion rates and decreased combined production. The lower depletion rates are largely the result of the write-down of natural gas and oil properties in March 2009.
- Decreased lease operating expenses of $3.7 million (after tax)
- Increased oil production of 5 percent, largely related to drilling activity in the Bakken area
- Lower general and administrative expense of $2.2 million (after tax)

Partially offsetting these increases were:

- Decreased natural gas production of 16 percent, largely related to normal production declines, as previously discussed
- Lower average realized natural gas prices of 11 percent
- Higher production taxes of $3.4 million (after tax)

Construction Materials and Contracting

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(Dollars in millions)			
Operating revenues	$361.6	$389.4	$511.4	$572.9
Operating expenses:				
Operation and maintenance	316.9	325.7	462.9	498.0
Depreciation, depletion and amortization	22.2	23.8	44.8	47.8
Taxes, other than income	9.2	9.8	16.5	17.3
	348.3	359.3	524.2	563.1
Operating income (loss)	13.3	30.1	(12.8)	9.8
Earnings (loss)	$5.7	$16.0	$(14.5)	$.3
Sales (000's):				
Aggregates (tons)	6,261	6,486	9,224	9,671
Asphalt (tons)	1,579	1,530	1,733	1,718
Ready-mixed concrete (cubic yards)	742	792	1,218	1,301

Three Months Ended June 30, 2010 and 2009 Earnings at the construction materials and contracting business decreased $10.3 million (65 percent) due to lower aggregate, ready-mixed concrete and liquid asphalt oil volumes and margins, as well as decreased construction and asphalt margins, which reflects the effects of the economic downturn and weather-related delays.

Partially offsetting the decreases was lower depreciation, depletion and amortization expense of $1.0 million (after tax), largely the result of lower property, plant and equipment balances.

Six Months Ended June 30, 2010 and 2009 Construction materials and contracting recognized a loss of $14.5 million compared to earnings of $300,000 for the comparable prior period due to lower aggregate, ready-mixed concrete and liquid asphalt oil volumes and margins, as well as decreased construction and asphalt margins, as previously discussed.

Partially offsetting the decreases was lower depreciation, depletion and amortization expense of $1.9 million (after tax), largely the result of lower property, plant and equipment balances, as well as lower selling, general and administrative expense of $1.2 million (after tax).

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,	
	2010	2009	2010	2009
	(In millions)			
Other:				
Operating revenues	$2.3	$2.7	$4.5	$5.4
Operation and maintenance	1.8	1.9	3.7	5.2
Depreciation, depletion and amortization	.4	.3	.8	.6
Taxes, other than income	.1	.1	.1	.1
Intersegment transactions:				
Operating revenues	$42.8	$36.2	$108.1	$98.9
Purchased natural gas sold	36.8	29.2	95.8	84.8
Operation and maintenance	6.0	7.0	12.3	14.1

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 2009 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 2010, diluted, are projected in the range of $1.10 to $1.35. The Company expects the percentage of 2010 earnings per common share by quarter to be in the following approximate ranges:
  - Third quarter – 30 percent to 35 percent
  - Fourth quarter – 20 percent to 25 percent

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

- The Company continually seeks opportunities to expand through strategic acquisitions and organic growth opportunities.

Electric and natural gas distribution
- The Company continues to realize efficiencies and enhanced service levels through its efforts to standardize operations, share services and consolidate back-office functions among its four utility companies.

- The Company has a 25 MW ownership interest in Wygen III, which commenced commercial operation on April 1, 2010. The WYPSC approved an increase, primarily related to the costs of Wygen III, in the amount of $2.7 million annually, or 13.1 percent, effective May 1, 2010.

- In April 2010, the Company filed an application with the NDPSC for an electric rate increase, as discussed in Note 18.

- The Company plans to file an application with the MTPSC for an electric rate increase in the third quarter of 2010. The request will include an increase related to the investment in infrastructure upgrades, recovery of the investment in renewable generation and the costs associated with the Big Stone Station II.

- The Company is developing a landfill methane gas recovery project in Billings, Montana to supplement the Company's gas supply portfolio. The project is expected to begin production in the fourth quarter of 2010, and upon total phase-in to recover up to 2,500 dk per day.

- The Company is analyzing potential projects for accommodating load growth and replacing purchased power contracts with company-owned generation. The Company is reviewing the construction of natural gas-fired combustion and wind generation.

- The Company is pursuing opportunities associated with the potential development of high voltage transmission lines and system enhancements targeted towards delivery of renewable energy from the wind rich regions that lie within its traditional electric service territory to major metropolitan areas. The Company has signed a contract to develop a 30-mile high-voltage power line in southeast North Dakota to move power to the electric grid from a proposed 150-MW wind farm being built by enXco for Xcel Energy. The $25 million project also will include substation upgrades. Pending regulatory approval, construction is expected to begin in 2011. Customers will not bear any of the costs associated with the project as costs will be recovered through an approved interconnect tariff.

- In June 2010, the Company placed into service a 10.5 MW expansion of its Diamond Willow wind farm in Montana, and the new 19.5 MW Cedar Hills wind farm in southwest North Dakota.

Construction services

- Work backlog as of June 30, 2010, was approximately $389 million, compared to $507 million at June 30, 2009, which included backlog related to the Fontainebleau project of $182 million. The Fontainebleau project was removed from backlog in the third quarter of 2009 after Fontainebleau's bankruptcy filing. Absent the Fontainebleau-related backlog, levels are $64–– million higher than one year ago. Backlog at March 31, 2010, was $400 million.

- Examples of new projects included in work backlog are solar projects in the Las Vegas area and substation related work.

- The Company anticipates margins in 2010 to be lower than 2009 levels.

- The Company is aggressively pursuing expansion in high voltage transmission and substation construction, renewable resource construction and military installation services. In late 2009, the Company was awarded the engineering, procurement and construction contract to build the 214-mile Montana Alberta Tie Line between Lethbridge, Alberta and Great Falls, Montana. In late June 2010, the Company received a notice to proceed with construction on the project.

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- The Company continues to focus on costs and efficiencies to enhance margins. Selling, general and administrative expenses are down 32 percent for the second quarter compared to one year ago.

- With its highly skilled technical workforce, this group is prepared to take advantage of government stimulus spending on transmission infrastructure.

Pipeline and energy services

- An incremental expansion to the Grasslands Pipeline of 75,000 Mcf per day went into service August 31, 2009. The firm capacity of the Grasslands Pipeline is at its ultimate full capacity of 213,000 Mcf per day.

- The Company continues to pursue expansion of facilities and services offered to customers. Energy development within its geographic region, which includes portions of Colorado, Wyoming, Montana and North Dakota, is expanding, most notably the Bakken Shale of North Dakota and eastern Montana. Ongoing energy development is expected to have many direct and indirect benefits to its business.

- The Company continues to pursue the expansion of its existing natural gas pipeline capacity by 30,000 Mcf per day in the Bakken production area in northwestern North Dakota. This expansion project is targeted for late 2011.

- The Company continues to see strong interest in its storage services. It has three natural gas storage fields, including the largest storage field in North America located near Baker, Montana. The Company is pursuing a project to increase its firm deliverability from the Baker Storage field by 125,000 Mcf per day and related transportation capacity. The Company has received commitment on approximately 30 percent of the total potential project and is moving forward on that phase, subject to regulatory approval, with a projected in-service date of November 2011.

Natural gas and oil production

- The Company expects to spend approximately $380 million in capital expenditures for 2010, approximately double the level of capital invested in 2009. This reflects further exploitation of existing properties, leasehold acquisitions in the Bakken and Niobrara oil shale plays and the acquisition of producing natural gas properties located in the Green River Basin. The capital expenditures forecasted reflect a shift from certain natural gas development activities to oil shale leasehold acquisitions, which will affect short-term production growth.

- Earlier this year, the Company acquired exploratory acreage of approximately 40,000 net acres in the North Dakota Bakken area, bringing its total acreage position in this oil play to more than 56,000 net acres. For the 40,000 net acres held in Stark County, the Heart River project, plans include drilling three exploratory wells this year to evaluate the acreage targeting the Three Forks formation. Lease terms extend up to five years including renewal options available to the Company. A total of 60 potential drilling sites have been identified in this area based on 640-acre spacing.

- The Company also acquired approximately 80,000 net exploratory acres in the emerging Niobrara oil play in Laramie and Goshen Counties in southeastern Wyoming. The Company plans to begin drilling exploratory wells in the area in 2011. Assuming 640-acre spacing, the Company has 120 potential drilling sites available on this acreage. Lease terms are generally five years with most having five-year renewal options available to the Company. Although this emerging play is still developing in terms of resource potential, early results by other producers in the play appear promising.

- The Company continues to pursue additional leasehold and reserve acquisitions which are not included in the current forecast.

- Because of reduced capital spending in 2009 and the redirecting of forecasted 2010 capital expenditures, along with delays in obtaining well completion/frac services, primarily in Texas, the Company expects its 2010 combined natural gas and oil production to be approximately 3 percent to 6 percent below 2009 levels.

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

Index*	Price Per Mcf
Ventura	$4.25 to $4.75
NYMEX	$4.50 to $5.00
CIG	$4.00 to $4.50

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

- Earnings guidance reflects estimated NYMEX crude oil prices for August through December in the range of $70 to $75 per barrel.

- For the last six months of 2010, the Company has hedged approximately 50 percent to 55 percent of its estimated natural gas production and 40 percent to 45 percent of its estimated oil production. For 2011, the Company has hedged 15 percent to 20 percent of its estimated natural gas production and 30 percent to 35 percent of its estimated oil production. For 2012, the Company has hedged 5 percent to 10 percent of its estimated natural gas production. The hedges that are in place as of August 2, 2010, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (MMBtu/Bbl)	Price (Per MMBtu/Bbl)
Natural Gas	Swap	HSC	7/10 - 12/10	809,600	$8.08
Natural Gas	Swap	NYMEX	7/10 - 12/10	1,840,000	$6.18
Natural Gas	Swap	NYMEX	7/10 - 12/10	920,000	$6.40
Natural Gas	Collar	NYMEX	7/10 - 12/10	920,000	$5.63-$6.00
Natural Gas	Swap	NYMEX	7/10 - 12/10	920,000	$5.855
Natural Gas	Swap	NYMEX	7/10 - 12/10	920,000	$6.045
Natural Gas	Swap	NYMEX	7/10 - 12/10	920,000	$6.045
Natural Gas	Swap	CIG	7/10 - 12/10	1,840,000	$5.03
Natural Gas	Swap	HSC	7/10 - 10/10	246,000	$5.57
Natural Gas	Swap	NYMEX	7/10 - 10/10	984,000	$5.645
Natural Gas	Swap	Ventura	7/10 - 12/10	920,000	$5.95
Natural Gas	Swap	NYMEX	7/10 - 12/10	2,024,000	$5.54
Natural Gas	Collar	NYMEX	7/10 - 3/11	1,370,000	$5.62-$6.50
Natural Gas	Swap	HSC	1/11 - 12/11	1,350,500	$8.00
Natural Gas	Swap	NYMEX	1/11 - 12/11	4,015,000	$6.1027
Natural Gas	Swap	NYMEX	1/11 - 12/11	3,650,000	$5.4975
Natural Gas	Swap	NYMEX	1/12 - 12/12	3,477,000	$6.27
Crude Oil	Collar	NYMEX	7/10 - 12/10	184,000	$60.00-$75.00
Crude Oil	Swap	NYMEX	7/10 - 12/10	184,000	$73.20
Crude Oil	Collar	NYMEX	7/10 - 12/10	184,000	$70.00-$86.00
Crude Oil	Swap	NYMEX	7/10 - 12/10	184,000	$83.05
Crude Oil	Collar	NYMEX	1/11 - 12/11	547,500	$80.00-$94.00
Crude Oil	Collar	NYMEX	1/11 - 12/11	365,000	$80.00-$89.00
Crude Oil	Collar	NYMEX	1/11 - 12/11	182,500	$77.00-$86.45
Crude Oil	Collar	NYMEX	1/11 - 12/11	182,500	$75.00-$88.00
Natural Gas	Basis Swap	Ventura	7/10 - 12/10	1,840,000	$0.25
Natural Gas	Basis Swap	Ventura	7/10 - 12/10	460,000	$0.245
Natural Gas	Basis Swap	Ventura	7/10 - 12/10	2,300,000	$0.25
Natural Gas	Basis Swap	Ventura	7/10 - 12/10	920,000	$0.225
Natural Gas	Basis Swap	Ventura	7/10 - 12/10	460,000	$0.23
Natural Gas	Basis Swap	Ventura	7/10 - 12/10	1,380,000	$0.23
Natural Gas	Basis Swap	CIG	7/10 - 12/10	2,024,000	$0.385
Natural Gas	Basis Swap	Ventura	1/11 - 3/11	450,000	$0.135
Natural Gas	Basis Swap	CIG	1/11 - 12/11	4,015,000	$0.395
Natural Gas	Basis Swap	CIG	1/12 - 12/12	2,745,000	$0.405
Natural Gas	Basis Swap	CIG	1/12 - 12/12	732,000	$0.41

Notes:

· 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.

· For all basis swaps, Index prices are below NYMEX prices and are reported as a positive amount in the Price column.

Construction materials and contracting

- Work backlog as of June 30, 2010, was approximately $677 million, $109 million higher than the March 31, 2010, backlog of $568 million. Backlog a year ago was $707 million. Private project backlog has decreased, however public work has increased over prior year levels.

- Examples of new large projects included in work backlog are several highway paving projects, a reclamation project, and an L.A. harbor deepening project.

- All of the markets served by the construction materials segment are seeing positive impacts related to the federal stimulus spending and the Company is well positioned to take advantage of this funding in the asphalt paving and liquid asphalt oil product lines. Federal transportation stimulus of $7.9 billion was directed to states where the Company operates. Of that amount, 41 percent was spent as of late July 2010, with the remaining $4.7 billion to be spent during the remainder of 2010 and 2011.

- The Company continues to pursue work related to energy projects, such as wind towers, transmission projects, geothermal and refineries. It is also pursuing opportunities for expansion of its existing business lines including initiatives aimed at capturing additional market share and expansion into new markets.

- The Company has a strong emphasis on operational efficiencies and cost reduction. Selling, general and administrative expenses are down 35 percent for the trailing 12 months through June 30, 2010, compared to the annual expenses in 2006, the peak earnings year for this segment.

- The Company expects volumes and margins to be lower in 2010 compared to 2009 as a result of the economic downturn. Liquid asphalt volumes were at record levels in 2009.

- The Company has planned green field expansions for the liquid asphalt oil business this year.

- As the country's 6th largest sand and gravel producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

- Of the five labor contracts that Knife River was negotiating, as reported in Items 1 and 2 – Business and Properties – General in the 2009 Annual Report, four have been ratified. The one 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 2009 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2009 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 2010 decreased $195.1 million from the comparable period in 2009 due to higher working capital requirements of $183.5 million, including decreased cash provided from receivables, largely at the construction services and natural gas and oil production businesses along with lower cash provided from net natural gas costs recoverable through rate adjustments at the natural gas distribution business.

Investing activities Cash flows used in investing activities in the first six months of 2010 increased $59.4 million from the comparable period in 2009 due to an increase in acquisition-related capital expenditures of $102.8 million, largely due to the acquisition of natural gas properties located in the Green River Basin, offset in part by decreased ongoing capital expenditures of $35.3 million, largely at the pipeline and energy services and natural gas and oil production businesses.

Financing activities Cash flows provided by financing activities in the first six months of 2010 increased $162.9 million from the comparable period in 2009 due to lower repayment of short-term borrowings and long-term debt of $98.5 million and $91.2 million, respectively, offset in part by lower issuance of long-term debt of $26.4 million.

Defined benefit pension plans

There were no material changes to the Company’s qualified noncontributory defined benefit pension plans from those reported in the 2009 Annual Report. For further information, see Note 17 and Part II, Item 7 in the 2009 Annual Report.

Capital expenditures

Net capital expenditures for the first six months of 2010 were $335.5 million and are estimated to be approximately $––––625 million for 2010. Estimated capital expenditures include:

- The acquisition of producing natural gas properties located in the Green River Basin in southwest Wyoming
- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering projects
- Further development of existing properties and leasehold acquisitions at the natural gas and oil production segment
- 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 2010 capital expenditures referred to previously. It is anticipated that all of the funds required for capital expenditures will be met from various sources, including internally generated funds; the Company's credit facilities, as described below; and through the issuance of long-term debt and the Company's equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at June 30, 2010. 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. For additional information on the covenants, certain other conditions and cross-default provisions, see Part II, Item 8 – Note 9, in the 2009 Annual Report.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries at June 30, 2010:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date	
			(Dollars in millions)							
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$125.0		$—	(b)	$—		6/21/11	
MDU Energy Capital, LLC	Master shelf agreement		$175.0		$165.0		$—		8/14/10	(c)(d)
Cascade Natural Gas Corporation	Revolving credit agreement		$50.0	(e)	$—		$1.9	(f)	12/28/12	(g)
Intermountain Gas Company	Revolving credit agreement		$65.0	(h)	$3.7		$—		8/31/10	(i)
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(j)	$400.0		$83.0	(b)	$25.8	(f)	12/13/12	
Williston Basin Interstate Pipeline Company	Uncommitted long-term private shelf agreement		$125.0		$87.5		$—		12/23/11	(c)

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (provisions allow for increased borrowings, 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.
(b) Amount outstanding under commercial paper program.
(c) Represents expiration of the ability to borrow additional funds under the agreement.
(d) Or such time as the agreement is terminated by either of the parties thereto.
(e) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(f) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.
(g) Provisions allow for an extension of up to two years upon consent of the banks.
(h) Certain provisions allow for increased borrowings, up to a maximum of $70 million.
(i) Intermountain plans to negotiate the extension or replacement of this agreement prior to its expiration.
(j) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.

In order to maintain the Company's and Centennial's respective commercial paper programs in the amounts indicated above, both the Company and Centennial must have revolving credit agreements in place at least equal to the amount of their commercial paper programs. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the above table.

MDU Resources Group, Inc. The Company’s revolving credit agreement supports its commercial paper program. 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. The Company’s objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. 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. If the Company were to experience a further downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

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 become too expensive, which the Company does not currently anticipate, the Company would seek alternative funding.

The Company's coverage of fixed charges including preferred stock dividends was 4.5 times for the 12 months ended June 30, 2010. Due to the $384.4 million after-tax noncash write-down of natural gas and oil properties in the first quarter of 2009, earnings were insufficient by $228.7 million to cover fixed charges for the 12 months ended December 31, 2009. If the $384.4 million after-tax noncash write-down is excluded, the coverage of fixed charges including preferred stock dividends would have been 4.6 times for the 12 months ended December 31, 2009. Common stockholders' equity as a percent of total capitalization was 62 percent and 63 percent at June 30, 2010 and December 31, 2009, respectively.

The coverage of fixed charges including preferred stock dividends, that excludes the effect of the after-tax noncash write-down 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-down excluded is 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.

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 million 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 have been and are expected to be used for corporate development purposes and other general corporate purposes. The Company did not issue any shares of stock in 2010 under the Sales Agency Financing Agreement. The Company has issued a total of approximately 3.2 million shares of stock under the Sales Agency Financing Agreement through June 30, 2010, resulting in total net proceeds of $63.1 million.

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.

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. 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. Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the capital markets. If Centennial were to experience a further downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

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 is 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.

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 19.

Centennial continues to guarantee CEM's obligations under a construction contract for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. For further information, see Note 19.

Contractual obligations and commercial commitments

There are no material changes in the Company's contractual obligations relating to long-term debt, estimated interest payments, purchase commitments and uncertain tax positions from those reported in the 2009 Annual Report.

The Company's contractual obligations relating to operating leases at June 30, 2010, increased $26.7 million or 22 percent from December 31, 2009. At June 30, 2010, the Company's contractual obligations related to operating leases totaled $150.7 million. The scheduled commitment amounts (for the twelve months ended June 30, of each year listed) total $28.4 million in 2011; $22.7 million in 2012; $18.5 million in 2013; $13.0 million in 2014; $6.5 million in 2015; and $61.6 million thereafter.

For more information on contractual obligations and commercial commitments, see Part II, Item 7 in the 2009 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 2009 Annual Report, and Notes 10 and 13.

The following table summarizes derivative agreements entered into by Fidelity, Cascade and Intermountain as of June 30, 2010. 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 2010	$5.93	12,344	$15,252
Natural gas swap agreements maturing in 2011	$6.14	9,016	$7,372
Natural gas swap agreement maturing in 2012	$6.27	3,477	$2,008
Natural gas basis swap agreements maturing in 2010	$.27	9,384	$162
Natural gas basis swap agreements maturing in 2011	$.37	4,465	$328
Natural gas basis swap agreements maturing in 2012	$.41	3,477	$285
Oil swap agreements maturing in 2010	$78.13	368	$437
Cascade			
Natural gas swap agreements maturing in 2010	$8.02	2,425	$(9,382)
Natural gas swap agreements maturing in 2011	$8.10	2,270	$(7,601)
Intermountain			
Natural gas swap agreement maturing in 2010	$4.96	1,661	$(1,485)
Natural gas swap agreement maturing in 2011	$4.96	2,889	$(429)

	Weighted Average Floor/Ceiling Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas collar agreements maturing in 2010	$5.63/$6.25	1,840	$1,474
Natural gas collar agreement maturing in 2011	$5.62/$6.50	450	$345
Oil collar agreements maturing in 2010	$65.00/$80.50	368	$(874)
Oil collar agreements maturing in 2011	$78.86/$90.64	1,278	$4,706

Interest rate risk

There were no material changes to interest rate risk faced by the Company from those reported in the 2009 Annual Report. For more information, see Part II, Item 7A in the 2009 Annual Report.

At June 30, 2010 and 2009, and December 31, 2009, 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 2009 Annual Report.

At June 30, 2010 and 2009, and December 31, 2009, 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, 2010, that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see Note 19, which is incorporated by reference.

ITEM 1A. RISK FACTORS

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

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

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

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

There are no material changes in the Company’s risk factors from those reported in Part I, Item 1A – Risk Factors in the 2009 Annual Report other than the risk associated with electric generation operations 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. 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.

Environmental and Regulatory Risks
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 international, 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 approximately 70 percent of Montana-

Dakota’s generating capacity. More than 90 percent of the electricity generated by Montana-Dakota is from coal-fired plants. 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 may be subject to regulation under climate change laws or regulations within the next few years. Implementation of treaties, 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. 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’s operations are and have been the subject of numerous lawsuits filed in connection with its CBNG development in the Montana and Wyoming Powder River Basin. If the plaintiffs are successful in the current 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 district court decided the case in favor of Fidelity, the Montana Supreme Court reversed the state district court’s decision on May 18, 2010, and ordered the Montana DEQ to reevaluate Fidelity’s permit applications under the appropriate predischarge treatment standards. The Montana DEQ has until November 14, 2010, to complete the permitting process, during which time Fidelity may continue to operate under its current permits. Fidelity will not be able to assess the impact to its operations until the final permits are issued.

In a separate proceeding in Montana state court, plaintiffs challenged the ROD adopted by the MBOGC in 2003 and alleged that various water management tools, including Fidelity’s water discharge permits, allow for the “wasting” of water in violation of the Montana State Constitution. On

March 5, 2010, the Montana First Judicial District Court determined that the water management tools used by Fidelity did not waste water in violation of the constitution. Once judgment is entered, the parties will have 60 days to appeal to the Montana Supreme Court. 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, 2010	—			
May 1 through May 31, 2010	36,450	$19.52		
June 1 through June 30, 2010	—			
Total	36,450			

(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 purchase 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 6, 2010	BY:	/s/ Doran N. Schwartz Doran N. Schwartz Vice President and Chief Financial Officer
		BY:	/s/ Nicole A. Kivisto Nicole A. Kivisto Vice President, Controller and Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.

+10(a)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated May 28, 2010
+10(b)	Agreement for Termination of Change of Control Employment Agreement, dated June 15, 2010, by and between MDU Resources Group, Inc. and Terry D. Hildestad
+10(c)	Form of Notice of Expiration of Coverage Period – Change of Control Employment Agreement, dated June 15, 2010, sent by MDU Resources Group, Inc. to William E. Schneider, John G. Harp, Steven L. Bietz, David L. Goodin, William R. Connors, Mark A. Del Vecchio, Nicole A. Kivisto, Cynthia J. Norland, Paul K. Sandness, Doran N. Schwartz and John P. Stumpf
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, 2010, 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.