MDU RESOURCES GROUP INC
Form 10-Q
August 05, 2011

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, 2011

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 29, 2011: 188,793,564 shares.

DEFINITIONS

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

Abbreviation or Acronym	
2010 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2010
Alusa	Tecnica de Engenharia Electrica - Alusa
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Big Stone Station II	Formerly proposed coal-fired electric generating facility near Big Stone City, South Dakota (the Company had anticipated ownership of at least 116 MW)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Brazilian Transmission Lines	Company's equity method investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE and a portion of the ownership interests in ECTE were sold in the fourth quarter of 2010)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
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
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
ECTE	Company's equity method investment in Empresa Catarinense de Transmissão de Energia S.A. (10.01 percent ownership interest at June 30, 2011, 14.99 percent ownership interest sold in the fourth quarter of 2010)
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency

2

ERISA	Employee Retirement Income Security Act of 1974
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IFRS	International Financial Reporting Standards
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
Knife River – Northwest	Knife River Corporation – Northwest, an indirect wholly owned subsidiary of Knife River (previously Morse Bros., Inc., name changed effective January 1, 2010)
kWh	Kilowatt-hour
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LTM	LTM, Inc., an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MBbls	Thousands of barrels
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
Mine Safety Act	Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006
MMBtu	Million Btu
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent – natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil
MMdk	Million decatherms
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana District Court	Montana Seventeenth Judicial District Court, Phillips County

MPPAA	Multiemployer Pension Plan Amendments Act of 1980

MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
Oil	Includes crude oil, condensate and natural gas liquids
OPUC	Oregon Public Utility Commission
Oregon Circuit Court	Circuit Court of the State of Oregon for the County of Klamath
Oregon DEQ	Oregon State Department of Environmental Quality
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
PRP	Potentially Responsible Party
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
SEC	U.S. Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
SourceGas	SourceGas Distribution LLC
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

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 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.

INDEX

6

PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$274,538	$272,177	$752,018	$732,422
Construction services, natural gas and oil production, construction materials and contracting, and other	656,219	634,267	1,080,544	1,008,799
Total operating revenues	930,757	906,444	1,832,562	1,741,221
Operating expenses:				
Fuel and purchased power	14,474	13,106	31,428	30,017
Purchased natural gas sold	101,538	97,441	346,224	331,133
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	70,028	68,437	137,989	131,421
Construction services, natural gas and oil production, construction materials and contracting, and other	536,608	516,854	896,408	830,642
Depreciation, depletion and amortization	83,290	81,547	167,964	160,225
Taxes, other than income	42,516	40,397	92,181	86,192
Total operating expenses	848,454	817,782	1,672,194	1,569,630
Operating income	82,303	88,662	160,368	171,591
Earnings from equity method investments	949	2,260	1,433	4,443
Other income	1,908	2,686	3,809	5,188
Interest expense	20,036	20,490	42,053	41,006
Income before income taxes	65,124	73,118	123,557	140,216
Income taxes	19,889	24,180	35,793	49,506
Income from continuing operations	45,235	48,938	87,764	90,710
Income (loss) from discontinued operations, net of tax (Note 9)	(168)	—	280	—
Net income	45,067	48,938	88,044	90,710

Dividends on preferred stocks	171	171	342	343
Earnings on common stock	$44,896	$48,767	$87,702	$90,367

(continued on next page)

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands, except per share amounts)			
Earnings per common share -- basic:				
Earnings before discontinued operations	$ .24	$ .26	$ .46	$ .48
Discontinued operations, net of tax	—	—	—	—
Earnings per common share -- basic	$ .24	$ .26	$ .46	$ .48
Earnings per common share -- diluted:				
Earnings before discontinued operations	$ .24	$ .26	$ .46	$ .48
Discontinued operations, net of tax	—	—	—	—
Earnings per common share -- diluted	$ .24	$ .26	$ .46	$ .48
Dividends per common share	$ .1625	$ .1575	$ .3250	$ .3150
Weighted average common shares outstanding -- basic	188,794	188,129	188,732	188,047
Weighted average common shares outstanding -- diluted	188,968	188,267	188,903	188,198

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

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

	June 30, 2011	June 30, 2010	December 31, 2010
	(In thousands, except shares and per share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$107,768	$65,792	$222,074
Receivables, net	566,366	502,454	583,743
Inventories	277,327	260,163	252,897
Deferred income taxes	33,732	17,755	32,890
Commodity derivative instruments	14,234	24,932	15,123
Prepayments and other current assets	71,604	98,203	60,441
Total current assets	1,071,031	969,299	1,167,168
Investments	116,368	142,212	103,661
Property, plant and equipment	7,394,616	7,085,632	7,218,503
Less accumulated depreciation, depletion and amortization	3,236,417	3,000,663	3,103,323
Net property, plant and equipment	4,158,199	4,084,969	4,115,180
Deferred charges and other assets:			
Goodwill	634,931	634,654	634,633
Other intangible assets, net	23,337	26,199	25,271
Other	253,515	255,473	257,636
Total deferred charges and other assets	911,783	916,326	917,540
Total assets	$6,257,381	$6,112,806	$6,303,549
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Short-term borrowings	$—	$3,700	$20,000
Long-term debt due within one year	62,571	72,551	72,797
Accounts payable	304,049	266,069	301,132
Taxes payable	45,065	39,976	56,186
Dividends payable	30,850	29,802	30,773
Accrued compensation	37,978	35,989	40,121
Commodity derivative instruments	18,686	20,160	24,428
Other accrued liabilities	224,220	172,446	222,639
Total current liabilities	723,419	640,693	768,076
Long-term debt	1,369,534	1,508,714	1,433,955
Deferred credits and other liabilities:			
Deferred income taxes	727,562	627,256	672,269
Other liabilities	711,516	708,403	736,447
Total deferred credits and other liabilities	1,439,078	1,335,659	1,408,716
Commitments and contingencies			
Stockholders' equity:			
Preferred stocks	15,000	15,000	15,000

Common stockholders' equity:			
Common stock			
Shares issued -- $1.00 par value, 189,332,485 at June 30, 2011, 188,672,532 at June 30, 2010 and 188,901,379 at December 31, 2010	189,332	188,673	188,901
Other paid-in capital	1,033,366	1,020,206	1,026,349
Retained earnings	1,523,546	1,407,950	1,497,439
Accumulated other comprehensive loss	(32,268)	(463)	(31,261)
Treasury stock at cost – 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,710,350	2,612,740	2,677,802
Total stockholders' equity	2,725,350	2,627,740	2,692,802
Total liabilities and stockholders' equity	$6,257,381	$6,112,806	$6,303,549

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

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)	
Operating activities:		
Net income	$88,044	$90,710
Income from discontinued operations, net of tax	280	—
Income from continuing operations	87,764	90,710
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	167,964	160,225
Earnings, net of distributions, from equity method investments	512	(1,899)
Deferred income taxes	60,960	35,758
Changes in current assets and liabilities, net of acquisitions:		
Receivables	17,259	27,149
Inventories	(29,154)	(12,442)
Other current assets	(19,600)	(32,471)
Accounts payable	(3,197)	(13,164)
Other current liabilities	(9,753)	(45,613)
Other noncurrent changes	(17,969)	(4,882)
Net cash provided by continuing operations	254,786	203,371
Net cash used in discontinued operations	(491)	—
Net cash provided by operating activities	254,295	203,371
Investing activities:		
Capital expenditures	(224,934)	(237,535)
Acquisitions, net of cash acquired	(157)	(106,548)
Net proceeds from sale or disposition of property	16,145	11,972
Investments	(9,955)	1,228
Net cash used in continuing operations	(218,901)	(330,883)
Net cash provided by discontinued operations	—	—
Net cash used in investing activities	(218,901)	(330,883)
Financing activities:		
Repayment of short-term borrowings	(20,000)	(6,600)
Issuance of long-term debt	6,000	82,992
Repayment of long-term debt	(81,202)	(814)
Proceeds from issuance of common stock	5,744	1,739
Dividends paid	(61,623)	(59,545)
Excess tax benefit on stock-based compensation	1,248	548
Net cash provided by (used in) continuing operations	(149,833)	18,320
Net cash provided by discontinued operations	—	—
Net cash provided by (used in) financing activities	(149,833)	18,320
Effect of exchange rate changes on cash and cash equivalents	133	(130)
Decrease in cash and cash equivalents	(114,306)	(109,322)

Cash and cash equivalents -- beginning of year	222,074	175,114
Cash and cash equivalents -- end of period	$107,768	$65,792

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

June 30, 2011 and 2010
(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 2010 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 2010 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, 2011, 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. Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $41.4 million and $21.6 million as of June 30, 2011 and December 31, 2010, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of June 30, 2011 and 2010, and December 31, 2010, was $14.2 million, $14.9 million and $15.3 million, respectively.

4. Inventories and natural gas in storage

Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. 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. Inventories consisted of:

	June 30, 2011	June 30, 2010	December 31, 2010
		(In thousands)	
Aggregates held for resale	$ 82,936	$ 83,535	$ 79,894
Materials and supplies	65,363	62,070	57,324
Natural gas in storage (current)	11,993	14,269	34,557
Merchandise for resale	33,435	28,438	30,182
Asphalt oil	55,729	51,956	25,234
Other	27,871	19,895	25,706
Total	$ 277,327	$ 260,163	$ 252,897

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 $47.2 million, $59.3 million, and $48.0 million at June 30, 2011 and 2010, and December 31, 2010, respectively.

5. Earnings per common share

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the applicable period. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the applicable period, plus the effect of outstanding stock options and performance share awards. For the three and six months ended June 30, 2011 and 2010, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

6. Cash flow information

Cash expenditures for interest and income taxes were as follows:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)	
Interest, net of amount capitalized	$ 40,646	$ 39,652
Income taxes	$ 12,887	$ 36,011

7. New accounting standards

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 were effective on January 1, 2011. The guidance requires additional disclosures, but it will not impact the Company's financial position, results of operations or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance is effective for the Company on January 1, 2012. The Company is evaluating the effects that adoption of this guidance will have.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. This guidance is effective for the Company on January 1, 2012, and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosure, but it will not impact the Company's financial position, results of operations or cash flows.

8. Comprehensive income

Comprehensive income is the sum of net income as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, foreign currency translation adjustments and gains on available-for-sale investments. For more information on derivative instruments, see Note 12.

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

	Three Months Ended June 30,	
	2011	2010
	(In thousands)	
Net income	$ 45,067	$ 48,938
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 $10,576 and $2,588 in 2011 and 2010, respectively	17,057	4,637
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $(2,191) and $3,191 in 2011 and 2010, respectively	(3,650)	5,259
Net unrealized gain (loss) on derivative instruments qualifying as hedges	20,707	(622)
Foreign currency translation adjustment, net of tax of $32 and $(307) in 2011 and 2010, respectively	50	(476)
Net unrealized gains on available-for-sale investments, net of tax of $47 in 2011	87	—
	20,844	(1,098)
Comprehensive income	$ 65,911	$ 47,840

14

	Six Months Ended June 30, 2011	2010
	(In thousands)	
Net income	$ 88,044	$ 90,710
Other comprehensive income (loss):		
Net unrealized gain (loss) on derivative instruments qualifying as hedges:		
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $(388) and $11,962 in 2011 and 2010, respectively	(1,217)	19,932
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $91 and $(1,166) in 2011 and 2010, respectively	155	(1,850)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(1,372)	21,782
Foreign currency translation adjustment, net of tax of $170 and $(929) in 2011 and 2010, respectively	262	(1,412)
Net unrealized gains on available-for-sale investments, net of tax of $55 in 2011	103	—
	(1,007)	20,370
Comprehensive income	$ 87,037	$ 111,080

9. Discontinued operations

In 2007, Centennial Resources sold CEM to Bicent Power LLC. In connection with the sale, Centennial Resources agreed to indemnify Bicent Power LLC and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. The Company incurred legal expenses related to this matter and had an income tax benefit related to favorable resolution of certain tax matters in the first quarter of 2011, which are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For further information, see Note 18.

10. 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, 2011, include ECTE.

In August 2006, MDU Brasil acquired ownership interests in the Brazilian Transmission Lines. The electric transmission lines are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

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. In November 2010, the Company completed the sale of its entire ownership interest in

15

ENTE and ERTE and 59.96 percent of its ownership interest in ECTE. One of the parties will purchase the Company's remaining ownership interests in ECTE over a four-year period. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE.

At June 30, 2011 and 2010, and December 31, 2010, the Company's equity method investments had total assets of $107.7 million, $369.9 million and $107.4 million, respectively, and long-term debt of $49.6 million, $157.1 million and $30.1 million, respectively. The Company's investment in its equity method investments was approximately $11.4 million, $57.9 million and $10.9 million, including undistributed earnings of $2.1 million, $11.1 million and $1.9 million, at June 30, 2011 and 2010, and December 31, 2010, respectively.

11. Goodwill and other intangible assets

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

Six Months Ended June 30, 2011	Balance as of January 1, 2011*	Goodwill Acquired During the Year** (In thousands)	Balance as of June 30, 2011*
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Construction services	102,870	298	103,168
Pipeline and energy services	9,737	—	9,737
Natural gas and oil production	—	—	—
Construction materials and contracting	176,290	—	176,290
Other	—	—	—
Total	$ 634,633	$ 298	$ 634,931

*Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.

** Includes a purchase price adjustment that was not material related to an acquisition in a prior period.

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

*Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.
** Includes purchase price adjustments that were not material related to acquisitions in a prior period.

Year Ended December 31, 2010	Balance as of January 1, 2010*	Goodwill Acquired During the Year** (In thousands)	Balance as of December 31, 2010*
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Construction services	100,127	2,743	102,870
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	$ 5,170	$ 634,633

*Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.
** Includes purchase price adjustments that were not material related to acquisitions in a prior period.

Other amortizable intangible assets were as follows:

	June 30, 2011	June 30, 2010	December 31, 2010
		(In thousands)	
Customer relationships	$ 21,702	$ 24,942	$ 24,942
Accumulated amortization	(9,395)	(10,688)	(11,625)
	12,307	14,254	13,317
Noncompete agreements	7,685	9,405	9,405
Accumulated amortization	(5,062)	(6,033)	(6,425)
	2,623	3,372	2,980
Other	12,899	12,063	13,217
Accumulated amortization	(4,492)	(3,490)	(4,243)
	8,407	8,573	8,974
Total	$ 23,337	$ 26,199	$ 25,271

Amortization expense for amortizable intangible assets for the three and six months ended June 30, 2011, was $1.0 million and $1.9 million, respectively. 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. Estimated amortization expense for amortizable intangible assets is $4.0 million in 2011, $3.9 million in 2012, $3.7 million in 2013, $3.4 million in 2014, $2.7 million in 2015 and $7.5 million thereafter.

12. 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, 2011, 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 2010 Annual Report.

Cascade and Intermountain

At June 30, 2011, Cascade held natural gas swap agreements, with total forward notional volumes of 676,000 MMBtu, which were not designated as hedges. Cascade utilizes, and Intermountain periodically utilizes, 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. Periodic changes in the fair market value of the derivative instruments are recorded 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, 2011, Cascade recorded the change in the fair market value of the derivative instruments of $1.9 million and $8.5 million, respectively, as a decrease to regulatory assets. 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 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's derivative instruments with credit-risk-related contingent features that are in a liability position at June 30, 2011, was $900,000. 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, 2011, was $900,000.

Fidelity

At June 30, 2011, Fidelity held natural gas swap agreements with total forward notional volumes of 23.3 million MMBtu, natural gas basis swap agreements with total forward notional volumes of 12.9 million MMBtu, and oil swap, collar and put option agreements with total forward notional volumes of 3.7 million Bbl, all of which were designated as cash flow hedging instruments. At June 30, 2011, Fidelity held an oil call option agreement with total forward notional volumes of 184,000 Bbl, which did not qualify for hedge accounting. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on its forecasted sales of natural gas and oil production.

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

The amount of hedge ineffectiveness was immaterial for the three and six months ended June 30, 2011, and 2010, and there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges. The gain on the derivative instrument that did not qualify for hedge accounting was reported in operating revenues on the Consolidated Statements of Income and was $1.9 million (before tax) and $179,000 (before tax) for the three and six months ended June 30, 2011, respectively.

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 8.

As of June 30, 2011, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 30 months. Based on June 30, 2011, fair values, over the next 12 months net losses of approximately $2.3 million (after tax) are estimated to 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 or any of its affiliates 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, 2011, was $24.5 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, 2011, was $24.5 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, 2011	Fair Value at June 30, 2010	Fair Value at December 31, 2010
			(In thousands)	
Designated as hedges	Commodity derivative instruments	$14,040	$24,932	$ 15,123
	Other assets – noncurrent	6,265	8,524	4,104
		20,305	33,456	19,227
Not designated as hedges	Commodity derivative instruments	194	—	—
	Other assets – noncurrent	—	—	—
		194	—	—
Total asset derivatives		$20,499	$33,456	$ 19,227

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at June 30, 2011	Fair Value at June 30, 2010	Fair Value at December 31, 2010
			(In thousands)	
Designated as hedges	Commodity derivative instruments	$17,780	$1,961	$ 15,069
	Other liabilities – noncurrent	6,735	—	6,483
		24,515	1,961	21,552
Not designated as hedges	Commodity derivative instruments	906	18,199	9,359
	Other liabilities – noncurrent	—	698	—
		906	18,897	9,359
Total liability derivatives		$25,421	$20,858	$ 30,911

13. Fair value measurements

The Company measures 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 $40.3 million, $20.2 million and $39.5 million, as of June 30, 2011 and 2010, and December 31, 2010, respectively, are classified as Investments on the Consolidated Balance Sheets. The fair value of these investments decreased $1.3 million (before tax) for the three months ended June 30, 2011, and increased $790,000 (before tax) for the six months ended June 30, 2011. 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 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 include auction rate securities, mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. The Company's auction rate securities, which totaled $11.4 million at June 30, 2011 and 2010, and December 31, 2010, 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. Unrealized gains or losses on mortgage-backed securities and U.S. Treasury securities are recorded in accumulated other comprehensive income (loss) as discussed in Note 8.

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, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at June 30, 2011
	(In thousands)			
Assets:				
Money market funds	$—	$8,297	$ —	$8,297
Available-for-sale securities:				
Insurance investment contract*	—	40,328	—	40,328
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,162	—	8,162
U.S. Treasury securities	—	1,969	—	1,969
Commodity derivative instruments - current	—	14,234	—	14,234
Commodity derivative instruments - noncurrent	—	6,265	—	6,265
Total assets measured at fair value	$—	$90,655	$ —	$90,655
Liabilities:				
Commodity derivative instruments - current	$—	$18,686	$ —	$18,686
Commodity derivative instruments - noncurrent	—	6,735	—	6,735
Total liabilities measured at fair value	$—	$25,421	$ —	$25,421

* The insurance investment contract invests approximately 34 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

	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)	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.

	Fair Value Measurements at December 31, 2010, Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Money market funds	$—	$166,620	$ —	$ 166,620
Available-for-sale securities:				
Fixed-income securities	—	11,400	—	11,400
Insurance investment contract*	—	39,541	—	39,541
Commodity derivative instruments – current	—	15,123	—	15,123
Commodity derivative instruments – noncurrent	—	4,104	—	4,104
Total assets measured at fair value	$—	$236,788	$ —	$ 236,788
Liabilities:				
Commodity derivative instruments – current	$—	$24,428	$ —	$ 24,428
Commodity derivative instruments – noncurrent	—	6,483	—	6,483
Total liabilities measured at fair value	$—	$30,911	$ —	$ 30,911

* The insurance investment contract invests approximately 35 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 31 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

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 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, other observable inputs or other sources, including pricing from outside sources such as the fund itself.

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. For the three and six months ended June 30, 2011, there were no transfers between Levels 1 and 2.

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, and 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, 2011	$ 1,432,105	$ 1,550,592
Long-term debt at June 30, 2010	$ 1,581,265	$ 1,718,477
Long-term debt at December 31, 2010	$ 1,506,752	$ 1,621,184

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

14. Income taxes

In the first quarter of 2011, the Company received favorable resolution of certain tax matters relating to the 2004 through 2006 tax years. As a result, the Company recorded an income tax benefit from continuing operations of $4.2 million. This resolution includes the effects of $2.8 million related to the reversal of unrecognized tax benefits that were previously established for the 2004 through 2006 tax years and associated interest of $600,000.

In the second quarter of 2011, the Company's unrecognized tax positions increased $3.6 million, excluding interest, largely due to tax positions under examination relating to the 2007 through 2009 tax years. The ultimate deductibility of these tax positions is highly certain but there is uncertainty about the timing of such deductibility. The Company anticipates the uncertainty about the timing of the deductibility will be resolved within the next 12 months.

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 ECTE.

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 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 ECTE.

The information below follows the same accounting policies as described in Note 1 of the Company's Notes to Consolidated Financial Statements in the 2010 Annual Report. Information on the Company's businesses was as follows:

Three Months Ended June 30, 2011	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 49,986	$ —	$ 4,807
Natural gas distribution	164,626	—	1,902
Pipeline and energy services	59,926	12,504	4,772
	274,538	12,504	11,481
Construction services	192,697	5,379	6,138
Natural gas and oil production	87,390	25,392	21,326
Construction materials and contracting	375,613	—	4,980
Other	519	2,301	971
	656,219	33,072	33,415
Intersegment eliminations	—	(45,576)	—
Total	$ 930,757	$ —	$ 44,896

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

Six Months Ended June 30, 2011	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
		(In thousands)	
Electric	$ 107,831	$ —	$ 13,331
Natural gas distribution	535,010	—	29,418
Pipeline and energy services	109,177	37,245	11,691
	752,018	37,245	54,440
Construction services	394,877	6,596	10,771
Natural gas and oil production	165,801	50,933	37,596
Construction materials and contracting	519,146	—	(16,423)
Other	720	4,589	1,318
	1,080,544	62,118	33,262
Intersegment eliminations	—	(99,363)	—
Total	$ 1,832,562	$ —	$ 87,702

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

The Other category recognized a loss of $168,000 and income of $280,000, from discontinued operations, net of tax, for the three and six months ended June 30, 2011, respectively. Earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from construction services, natural gas and oil production, construction materials and contracting, and other are all from nonregulated operations.

16. Employee benefit plans

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

Three Months Ended June 30,	Pension Benefits 2011	Pension Benefits 2010	Other Postretirement Benefits 2011	Other Postretirement Benefits 2010
		(In thousands)		
Components of net periodic benefit cost:				
Service cost	$ 827	$ 501	$ 383	$ 374
Interest cost	4,959	4,004	1,161	1,317
Expected return on assets	(5,727)	(4,992)	(1,308)	(1,577)
Amortization of prior service cost (credit)	44	31	(669)	(915)
Amortization of net actuarial (gain) loss	1,049	256	(53)	67
Amortization of net transition obligation	—	—	531	613
Curtailment loss	1,218	—	—	—
Net periodic benefit cost, including amount capitalized	2,370	(200)	45	(121)
Less amount capitalized	287	107	(28)	37
Net periodic benefit cost	$ 2,083	$ (307)	$ 73	$ (158)

Six Months Ended June 30,	Pension Benefits 2011	Pension Benefits 2010	Other Postretirement Benefits 2011	Other Postretirement Benefits 2010
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 1,654	$ 1,305	$ 722	$ 731
Interest cost	9,919	8,930	2,350	2,594
Expected return on assets	(11,427)	(10,684)	(2,526)	(2,969)
Amortization of prior service cost (credit)	87	69	(1,338)	(1,779)
Amortization of net actuarial loss	2,592	1,228	258	455
Amortization of net transition obligation	—	—	1,062	1,145
Curtailment loss	1,218	—	—	—
Net periodic benefit cost, including amount capitalized	4,043	848	528	177
Less amount capitalized	535	383	(95)	84
Net periodic benefit cost	$ 3,508	$ 465	$ 623	$ 93

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011, all benefit and service accruals for an additional union plan were frozen. These employees will be 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, 2011, was $1.9 million and $4.0 million, respectively. 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.

17. Regulatory matters and revenues subject to refund

In April 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 included the investment in infrastructure upgrades, recovery of the investment in renewable generation,

the costs associated with Big Stone Station II and the significant loss of wholesale sales margins. In June 2010, the NDPSC approved an interim increase of $7.6 million effective with service rendered June 18, 2010. In June 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. In July 2010, Montana-Dakota filed an amendment to its application to exclude the 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. In November 2010, Montana-Dakota and the NDPSC Advocacy Staff filed a second settlement agreement resolving certain issues raised by the NDPSC Advocacy Staff in its investigation of the rate increase application. Montana-Dakota revised its requested rate increase to $8.8 million annually or 7.7 percent as a result of the settlements, the exclusion of the Big Stone Station II development costs and other adjustments. The NDPSC Advocacy Staff sought reductions of $8.3 million annually from Montana-Dakota's requested increase. A hearing on the application was held in November 2010. On March 14, 2011, Montana-Dakota, the NDPSC Advocacy Staff and the Missouri Valley Resource Council filed a settlement agreement that resolved all outstanding issues in the case, resulting in an increase of $7.6 million annually. On June 8, 2011, the NDPSC approved the settlement agreements. Final rates were implemented effective with service rendered July 22, 2011.

On May 20, 2011, Montana-Dakota filed an application with the NDPSC requesting advance determination of prudence that the addition of the air quality control system at the Big Stone Station, to comply with the Clean Air Act and the South Dakota Regional Haze Implementation Plan, is reasonable and prudent. An order is expected in early 2012.

On July 7, 2011, Montana-Dakota filed for an advance determination of prudence with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities projected to be in service in 2015. The turbine will be located on company owned property that is adjacent to Montana-Dakota's Heskett Generating Station near Mandan, North Dakota, and is required to meet the capacity requirements of Montana-Dakota's integrated electric system service customers. The capacity will be a partial replacement for third party contract capacity expiring in 2015. Project cost is estimated to be $85.6 million. An order is expected in the first quarter of 2012.

In August 2010, Montana-Dakota filed an application with the MTPSC for an electric rate increase. Montana-Dakota requested a total increase of $5.5 million annually or approximately 13 percent above current rates. The requested increase included the investment in infrastructure upgrades, recovery of the investment in renewable generation, the costs associated with Big Stone Station II and the significant loss of wholesale sales margins. Montana-Dakota requested an interim increase of $3.1 million or approximately 7.4 percent. On February 8, 2011, the MTPSC approved an interim increase of $2.6 million or approximately 6.28 percent, effective with service rendered February 14, 2011. On May 9, 2011, Montana-Dakota and intervenors to the case filed a settlement agreement with the MTPSC at the interim increase level. The MTPSC held a hearing on the settlement on June 29, 2011, and approved the settlement agreement on July 26, 2011.

On March 21, 2011, the WUTC filed a complaint against Cascade, alleging safety violations in the operations of its natural gas distribution system. For more information, see Note 18.

18. Contingencies

The Company has reserved $40.7 million and $45.3 million for potential liabilities related to litigation and environmental matters as of June 30, 2011 and December 31, 2010, respectively, which includes amounts that may be reserved for matters discussed in litigation and environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract 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, which letter of credit expired in November 2010. 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 $149.7 million. 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 Resources for indemnification under the 2007 purchase and sale agreement for indemnifiable losses, including defense fees and costs which CEM and Bicent Power LLC have stated are more than $10.0 million, arising from LPP's arbitration demand and related to Centennial Resources' ownership of CEM prior to its sale to Bicent Power LLC. The Company believes the claims against Centennial and Centennial Resources are without merit and intends to vigorously defend against such claims. Centennial and Centennial Resources filed a complaint with the Supreme Court of the State of New York in November 2010, against CEM and Bicent Power LLC seeking damages for breach of contract and other relief including specific performance of the 2007 purchase and sale agreement allowing for Centennial Resources' participation in the arbitration proceeding and replacement of the letter of credit. On January 28, 2011, CEM and Bicent Power LLC filed a motion to dismiss the complaint filed by Centennial and Centennial Resources. On July 6, 2011, the Supreme Court of the State of New York entered an order granting CEM's motion to dismiss the complaint against it for lack of jurisdiction. The Supreme Court of the State of New York also dismissed one of the claims against Bicent Power LLC but denied Bicent Power LLC's motion to dismiss the remaining claims against it including the claims for breach of contract damages and specific performance of the 2007 purchase and sale agreement. The arbitration hearing on LPP's claim is currently scheduled for late in the third quarter of 2011.

Construction Materials In 2009, LTM provided pavement work under a subcontract for reconstruction at the Klamath Falls Airport owned by the City of Klamath Falls, Oregon. In October 2010, the City of Klamath Falls filed a complaint in Oregon Circuit Court against the project's general contractor alleging the work performed by LTM is defective. The general contractor tendered the defense and indemnity of the claim to LTM and its insurance carrier. On January 18, 2011, the general contractor served a third party complaint against LTM seeking indemnity and contribution for damages imposed on the general contractor. LTM filed a fourth-party complaint seeking contribution and indemnity for damages imposed on LTM against the project engineer firm which prepared the specifications for the airport runway. LTM's insurance carrier accepted defense of the complaint against the general contractor and the third party complaint against LTM subject to reservation of its rights under the applicable insurance policy. Damages, including removal and replacement of the paved runway, were estimated by the plaintiff in its complaint as $6.0 million to $11.0 million. The Oregon Circuit Court granted a motion by LTM to dismiss certain of the plaintiff's claims relating to approximately $5.0 million of damages but allowed the plaintiff to amend its complaint. In its amended complaint, the plaintiff asserts new claims with estimated damages of $21.9 million plus interest and attorney fees. LTM believes its work met the specifications of the subcontract and expects to vigorously defend against the claims.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel Bitter Creek to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of Bitter Creek's pipeline gathering systems in Montana. Bitter Creek resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered Bitter Creek into arbitration. An arbitration hearing was held in August 2010. In October 2010, Bitter Creek was notified that the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, Bitter Creek, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010. On April 20, 2011, the Colorado State District Court entered an order denying a motion by Bitter Creek to vacate the arbitration award and granting a motion by SourceGas to confirm the arbitration award as a court judgment. The Colorado State District Court also awarded $293,000 to SourceGas for legal fees and expense. Bitter Creek filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals on April 28, 2011.

In related matters, Noble Energy, Inc. made a written demand in December 2010, to Bitter Creek and SourceGas for arbitration under the gathering contract between Bitter Creek and SourceGas. Noble Energy, Inc. contends it is a third party beneficiary of the contract and alleged it is damaged by the increased operating pressures demanded by SourceGas on the natural gas gathering system. Bitter Creek filed a complaint in Colorado State District Court to enjoin arbitration by Noble Energy, Inc. On July 8, 2011, Bitter Creek and Noble Energy, Inc. entered into a settlement agreement to dismiss all claims between them without prejudice including withdrawal of Noble Energy, Inc.'s demand for arbitration. In July 2010, Omimex Canada, Ltd. filed a complaint against Bitter Creek in Montana District Court alleging Bitter Creek breached a separate gathering contract with Omimex Canada, Ltd. as a result of the increased operating pressures on the same natural gas gathering system. Omimex Canada, Ltd. seeks unspecified damages and injunctive relief.

Natural Gas Distribution The WUTC on March 21, 2011, filed a complaint against Cascade, alleging pipeline safety violations in the operation of its natural gas distribution system. The complaint alleged more than 360 violations of pipeline safety regulations and sought relief including unspecified monetary penalties. Cascade filed its answer to the complaint admitting some and denying other of the alleged violations. Cascade and the WUTC staff entered into a settlement agreement filed with the WUTC on July 13, 2011, which was approved by the WUTC on August 3, 2011. The settlement provides for an immediate cash payment by Cascade of $425,000 and suspended penalties totaling up to $1.8 million which Cascade will be required to pay if it fails to comply with action items for remediation of violations and implementation of safety program improvements within timelines specified in the agreement. The Company's leadership is committed to pipeline safety compliance and over the past year and a half substantial resources have been invested by Cascade to improve pipeline safety documentation and procedures. Cascade recognized certain compliance issues and has been working with the WUTC to become fully compliant. Cascade believes most of the violations have been or are in the process of being remedied and intends to make significant additional technological and other investments over the next year to comply with the requirements of the settlement agreement and improve its compliance procedures and results.

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, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River – Northwest 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 Knife River – Northwest 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 Knife River – Northwest 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. Knife River – Northwest 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 Portland Harbor Natural Resource 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, Knife River – Northwest does not believe it is a Responsible Party. In addition, Knife River – Northwest 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. Knife River – Northwest 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 Knife River – Northwest and others to recover LWG's investigation costs to the extent Knife River – Northwest 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, Knife River – Northwest 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; however, Cascade anticipates its proportional share could be approximately fifty percent.

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. In October 2010, Cascade received notice from the United States Coast Guard that a hazardous substance appearing to be manufactured gas plant waste was released into the waterway from an abandoned pipe located on the shoreline in the vicinity of the former manufactured gas plant. Cascade subsequently received an administrative order from the United States Coast Guard requiring Cascade to remove the abandoned pipe and conduct other associated time-critical actions. The work satisfying the administrative order was completed by Cascade in November 2010. It is expected that subsequent remedial action at the site will be conducted under the oversight of the EPA. On June 27, 2011, the EPA provided Cascade with a draft administrative settlement agreement and statement of work for performance of a remediation investigation and feasibility study of the site. Cascade intends to meet with the EPA and discuss the draft agreement and statement of work with the intent of reaching consensus on the scope and schedule for the remediation investigation and feasibility study. Cascade has reserved $6.4 million for remediation of this site. In April 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 WUTC approved the petition in September 2010, subject to conditions set forth in the order.

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 and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. The remediation investigation and feasibility study report are expected to be completed by late 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. 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

Centennial guaranteed CEM's obligations under a construction contract. For further information, see litigation in this note.

In connection with the sale of the Brazilian Transmission Lines, as discussed in Note 10, Centennial has agreed to 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 sale of the Brazilian Transmission Lines.

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, 2011, expire in the years ranging from 2011 to 2012; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. The amount outstanding by Fidelity was $13.5 million and was reflected on the Consolidated Balance Sheet, at June 30, 2011. 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, 2011, the fixed maximum amounts guaranteed under these agreements aggregated $127.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $27.8 million in 2011; $73.4 million in 2012; $18.2 million in 2013; $300,000 in 2014; $100,000 in 2015; $100,000 in 2016; $800,000 in 2018; $300,000 in 2019; $2.6 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 $1.3 million and was reflected on the Consolidated Balance Sheet at June 30, 2011. 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, some of which are guaranteed by other subsidiaries of the Company. At June 30, 2011, the fixed maximum amounts guaranteed under these letters of credit, aggregated $27.4 million. In 2011 and 2012, $21.6 million and $5.8 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at June 30, 2011.

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, 2011, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. 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, 2011, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the 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 these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at June 30, 2011.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries, as well as an arbitration award. 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, 2011, approximately $688 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, revolving credit facilities and the issuance from time to time of debt and equity securities. 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 and environmental 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. The Company continues to review its strategic opportunities with respect to this business segment.

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; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other natural gas pipeline and energy services 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 add value by increasing both reserves and production over the long term so as to generate competitive returns on investment.

Challenges Volatility in natural gas and oil prices; timely receipt of necessary permits and approvals; environmental and regulatory requirements; 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; 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 lower margins. Delays in the multiple year 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 Item 1A – Risk Factors, as well as Part I, Item 1A – Risk Factors in the 2010 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,	
	2011	2010	2011	2010
	(Dollars in millions, where applicable)			
Electric	$4.8	$5.0	$13.3	$10.8
Natural gas distribution	1.9	.1	29.4	23.4
Construction services	6.1	2.9	10.8	3.1
Pipeline and energy services	4.8	9.5	11.7	18.3
Natural gas and oil production	21.3	24.0	37.6	46.3
Construction materials and contracting	5.0	5.7	(16.4)	(14.5)
Other	1.1	1.6	1.1	3.0
Earnings before discontinued operations	45.0	48.8	87.5	90.4
Income (loss) from discontinued operations, net of tax	(.1)	—	.2	—
Earnings on common stock	$44.9	$48.8	$87.7	$90.4
Earnings per common share – basic:				
Earnings before discontinued operations	$.24	$.26	$.46	$.48
Discontinued operations, net of tax	—	—	—	—
Earnings per common share – basic	$.24	$.26	$.46	$.48
Earnings per common share – diluted:				
Earnings before discontinued operations	$.24	$.26	$.46	$.48
Discontinued operations, net of tax	—	—	—	—
Earnings per common share – diluted	$.24	$.26	$.46	$.48
Return on average common equity for the 12 months ended			8.9%	10.0%

Three Months Ended June 30, 2011 and 2010 Consolidated earnings for the quarter ended June 30, 2011, decreased $3.9 million from the comparable prior period largely due to:

- Decreased transportation volumes and lower storage services revenue at the pipeline and energy services business
- Decreased natural gas production, lower average realized natural gas prices, increased lease operating expenses and higher production and property taxes, partially offset by higher average realized oil prices at the natural gas and oil production business

Partially offsetting these decreases were:

- Higher construction workloads and margins in the Western region at the construction services business
- Increased retail sales volumes at the natural gas distribution business

Six Months Ended June 30, 2011 and 2010 Consolidated earnings for the six months ended June 30, 2011, decreased $2.7 million primarily due to:

- Lower average realized natural gas prices, decreased natural gas production, higher depreciation, depletion and amortization expense and increased lease operating expenses, partially offset by higher average realized oil prices at the natural gas and oil production business
- Decreased transportation volumes, lower storage services revenue and lower gathering volumes, partially offset by lower operation and maintenance expense at the pipeline and energy services business

Partially offsetting these decreases were:

- Higher construction workloads and margins in the Western region at the construction services business
- Increased retail sales volumes and lower income taxes, partially offset by higher regulated operation and maintenance expense at the natural gas distribution 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,	
	2011	2010	2011	2010
	(Dollars in millions, where applicable)			
Operating revenues	$50.0	$45.7	$107.8	$95.4
Operating expenses:				
Fuel and purchased power	14.5	13.1	31.4	30.0
Operation and maintenance	18.3	16.2	34.3	31.4
Depreciation, depletion and amortization	7.9	6.1	16.1	11.9
Taxes, other than income	2.5	2.2	5.0	4.8
	43.2	37.6	86.8	78.1
Operating income	6.8	8.1	21.0	17.3
Earnings	$4.8	$5.0	$13.3	$10.8
Retail sales (million kWh)	614.6	615.2	1,409.3	1,365.0
Sales for resale (million kWh)	21.8	7.6	28.5	37.4
Average cost of fuel and purchased power per kWh	$.021	$.020	$.021	$.020

Three Months Ended June 30, 2011 and 2010 Electric earnings decreased $200,000 (3 percent) due to:

- Higher operation and maintenance expense of $1.3 million (after tax), primarily increased benefit and payroll-related costs, as well as increased contract services

39

- Increased depreciation, depletion and amortization expense of $1.1 million (after tax), including the effects of higher property, plant and equipment balances
- Lower other income of $800,000 (after tax), primarily lower allowance for funds used during construction related to electric generation projects, which were placed in service in 2010
- Higher net interest expense of $700,000 (after tax), including lower capitalized interest

Partially offsetting these decreases were:

- Lower income taxes of $2.2 million, primarily related to a reduction of deferred income taxes associated with benefits
- Higher electric retail sales margins, primarily due to implementation of interim rates in North Dakota and Montana

Six Months Ended June 30, 2011 and 2010 Electric earnings increased $2.5 million (23 percent) due to:

- Higher electric retail sales margins, primarily due to implementation of interim rates in North Dakota and Montana, as well as higher rates in Wyoming
- Lower income taxes of $3.5 million, including a reduction of deferred income taxes as previously discussed, as well as an income tax benefit of $1.2 million related to favorable resolution of certain income tax matters

Partially offsetting these increases were:

- Increased depreciation, depletion and amortization expense of $2.6 million (after tax), including the effects of higher property, plant and equipment balances
- Lower other income of $1.9 million (after tax), as previously discussed
- Higher operation and maintenance expense of $1.8 million (after tax), as previously discussed
- Higher net interest expense of $1.5 million (after tax), as previously discussed

Natural Gas Distribution

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(Dollars in millions, where applicable)			
Operating revenues	$164.6	$160.1	$535.0	$509.2
Operating expenses:				
Purchased natural gas sold	102.0	98.9	359.4	344.1
Operation and maintenance	33.3	34.4	67.6	67.1
Depreciation, depletion and amortization	11.2	10.7	22.4	21.4
Taxes, other than income	10.6	10.5	28.4	27.0
	157.1	154.5	477.8	459.6
Operating income	7.5	5.6	57.2	49.6
Earnings	$1.9	$.1	$29.4	$23.4
Volumes (MMdk):				
Sales	17.3	15.6	61.3	53.7
Transportation	25.6	28.9	59.7	63.4
Total throughput	42.9	44.5	121.0	117.1
Degree days (% of normal)*				
Montana-Dakota	120%	96%	112%	98%
Cascade	118%	118%	107%	95%
Intermountain	141%	132%	113%	103%
Average cost of natural gas, including transportation, per dk	$5.88	$6.33	$5.87	$6.41

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

Three Months Ended June 30, 2011 and 2010 Earnings at the natural gas distribution business increased $1.8 million compared to the prior year due to:

- Increased retail sales volumes, largely resulting from colder weather than last year
- Lower income taxes of $1.0 million, primarily related to a reduction of deferred income taxes associated with benefits

Partially offsetting these increases were:

- Higher regulated operation and maintenance expense of $500,000 (after tax), including higher benefit-related costs
- Increased depreciation, depletion and amortization expense of $300,000 (after tax), primarily resulting from higher property, plant and equipment balances

The previous table also reflects lower revenue and lower operation and maintenance expense related to pipeline project activity.

Six Months Ended June 30, 2011 and 2010 Earnings at the natural gas distribution business increased $6.0 million (26 percent) due to:

- Increased retail sales volumes, largely resulting from colder weather than last year
- Lower income taxes of $2.0 million, as previously discussed

41

Partially offsetting the earnings increase were:

- Higher regulated operation and maintenance expense of $1.9 million (after tax), primarily higher benefit-related costs
- Increased depreciation, depletion and amortization expense of $600,000 (after tax), as previously discussed

The previous table also reflects lower revenue and lower operation and maintenance expense related to pipeline project activity.

Construction Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Operating revenues	$198.1	$188.2	$401.5	$341.3
Operating expenses:				
Operation and maintenance	178.3	173.2	363.2	315.0
Depreciation, depletion and amortization	2.8	3.1	5.8	6.3
Taxes, other than income	5.5	6.1	13.2	12.6
	186.6	182.4	382.2	333.9
Operating income	11.5	5.8	19.3	7.4
Earnings	$6.1	$2.9	$10.8	$3.1

Three Months Ended June 30, 2011 and 2010 Construction services earnings increased $3.2 million (110 percent) due to higher construction workloads and margins in the Western region, partially offset by lower construction workloads and margins in the Mountain region. Also contributing to the earnings increase were higher equipment and electrical supply sales.

Six Months Ended June 30, 2011 and 2010 Construction services earnings increased $7.7 million due to higher construction workloads and margins in the Western region, partially offset by lower construction margins in the Mountain region. Also contributing to the earnings increase were higher equipment and electrical supply sales.

Pipeline and Energy Services

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(Dollars in millions)			
Operating revenues	$72.4	$80.5	$146.4	$169.1
Operating expenses:				
Purchased natural gas sold	33.9	35.3	68.0	82.8
Operation and maintenance	18.6	17.8	36.2	33.0
Depreciation, depletion and amortization	6.4	6.5	12.8	12.9
Taxes, other than income	3.4	3.2	7.0	6.2
	62.3	62.8	124.0	134.9
Operating income	10.1	17.7	22.4	34.2
Earnings	$4.8	$9.5	$11.7	$18.3
Transportation volumes (MMdk)	25.8	44.3	53.1	74.8
Gathering volumes (MMdk)	16.9	19.3	34.4	38.4
Customer natural gas storage balance (MMdk):				
Beginning of period	32.9	43.5	58.8	61.5
Net injection (withdrawal)	(1.2)	20.7	(27.1)	2.7
End of period	31.7	64.2	31.7	64.2

Three Months Ended June 30, 2011 and 2010 Pipeline and energy services earnings decreased $4.7 million (50 percent) due to:

- Decreased transportation volumes of $3.1 million (after tax), largely lower volumes transported to storage
- Lower storage services revenue of $1.7 million (after tax), largely lower storage balances
- Lower gathering volumes of $900,000 (after tax)

Partially offsetting the earnings decrease was lower operation and maintenance expense of $1.0 million (after tax), primarily lower legal-related costs and contract services. This decrease excludes the effects of energy-related service projects.

The previous table also reflects higher revenue and higher operation and maintenance expense related to energy-related service projects.

Six Months Ended June 30, 2011 and 2010 Pipeline and energy services earnings decreased $6.6 million (36 percent) due to:

- Decreased transportation volumes of $3.8 million (after tax), largely lower volumes transported to storage
- Lower storage services revenue of $2.1 million (after tax), largely lower storage balances
- Lower gathering volumes of $1.6 million (after tax)

Partially offsetting the earnings decrease was lower operation and maintenance expense of $700,000 (after tax), primarily lower legal-related costs and contract services. This decrease excludes the effects of energy-related service projects.

43

The previous table also reflects higher revenue and higher operation and maintenance expense related to energy-related service projects.

Natural Gas and Oil Production

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(Dollars in millions, where applicable)			
Operating revenues:				
Natural gas	$44.3	$55.2	$89.7	$112.8
Oil	68.5	55.6	127.0	105.6
	112.8	110.8	216.7	218.4
Operating expenses:				
Operation and maintenance:				
Lease operating costs	18.4	16.3	36.4	32.1
Gathering and transportation	5.6	5.9	11.3	11.8
Other	9.2	8.8	17.5	17.4
Depreciation, depletion and amortization	33.4	32.5	67.6	62.1
Taxes, other than income:				
Production and property taxes	10.5	9.0	20.5	18.5
Other	.2	.1	.5	.5
	77.3	72.6	153.8	142.4
Operating income	35.5	38.2	62.9	76.0
Earnings	$21.3	$24.0	$37.6	$46.3
Production:				
Natural gas (MMcf)	11,253	12,809	23,011	25,052
Oil (MBbls)	821	831	1,623	1,592
Total Production (MMcfe)	16,180	17,794	32,750	34,602
Average realized prices (including hedges):				
Natural gas (per Mcf)	$3.94	$4.31	$3.90	$4.50
Oil (per Bbl)	$83.42	$66.88	$78.26	$66.36
Average realized prices (excluding hedges):				
Natural gas (per Mcf)	$3.49	$3.30	$3.44	$3.92
Oil (per Bbl)	$89.25	$67.21	$84.31	$66.83
Average depreciation, depletion and amortization rate, per equivalent Mcf	$1.96	$1.74	$1.96	$1.71
Production costs, including taxes, per equivalent Mcf:				
Lease operating costs	$1.14	$.91	$1.11	$.93
Gathering and transportation	.34	.33	.34	.34
Production and property taxes	.65	.51	.63	.53
	$2.13	$1.75	$2.08	$1.80

Three Months Ended June 30, 2011 and 2010 Natural gas and oil production earnings decreased $2.7 million (11 percent) due to:

- Decreased natural gas production of 12 percent, largely related to weather and normal production declines at existing properties, partially offset by production from the Green River Basin properties, which were acquired in late April 2010
- Lower average realized natural gas prices of 9 percent
- Increased lease operating expenses of $1.3 million (after tax), including higher well maintenance costs
- Higher production and property taxes of $900,000 (after tax), largely resulting from higher oil prices excluding hedges
- Higher depreciation, depletion and amortization expense of $600,000 (after tax), due to higher depletion rates
- Decreased oil production of 1 percent, largely related to weather and normal production declines at existing properties, partially offset by drilling activity in the Bakken area, as well as from the South Texas properties

Partially offsetting these decreases were higher average realized oil prices of 25 percent.

Six Months Ended June 30, 2011 and 2010 Natural gas and oil production earnings decreased $8.7 million (19 percent) due to:

- Lower average realized natural gas prices of 13 percent
- Decreased natural gas production of 8 percent, as previously discussed
- Higher depreciation, depletion and amortization expense of $3.4 million (after tax), as previously discussed
- Increased lease operating expenses of $2.7 million (after tax), including higher well maintenance costs and costs associated with properties acquired in late April 2010
- Higher production and property taxes of $1.3 million (after tax), largely resulting from higher oil prices excluding hedges

Partially offsetting these decreases were:

- Higher average realized oil prices of 18 percent
- Increased oil production of 2 percent, largely related to drilling activity in the Bakken area, as well as from the South Texas properties, partially offset by weather and normal production declines at certain properties

Construction Materials and Contracting

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(Dollars in millions)			
Operating revenues	$375.6	$361.6	$519.2	$511.4
Operating expenses:				
Operation and maintenance	334.2	316.9	481.1	462.9
Depreciation, depletion and amortization	21.2	22.2	42.6	44.8
Taxes, other than income	9.8	9.2	17.5	16.5
	365.2	348.3	541.2	524.2
Operating income (loss)	10.4	13.3	(22.0)	(12.8)
Earnings (loss)	$5.0	$5.7	$(16.4)	$(14.5)
Sales (000's):				
Aggregates (tons)	6,479	6,261	9,306	9,224
Asphalt (tons)	1,842	1,579	2,007	1,733
Ready-mixed concrete (cubic yards)	698	742	1,095	1,218

Three Months Ended June 30, 2011 and 2010 Earnings at the construction materials and contracting business decreased $700,000 (12 percent) due to:

- Lower earnings of $2.3 million (after tax), resulting from lower ready-mixed concrete and other product line margins and volumes, largely due to increased competition, less available work and weather-related delays, partially offset by higher asphalt volumes and margins
- Lower gains of $1.6 million (after tax) from the sale of property, plant and equipment

Partially offsetting the decreases were:

- Increased construction margins of $1.5 million (after tax), largely due to increased margins and volumes in the Pacific region
- Lower selling, general and administrative costs of $800,000 (after tax), largely lower payroll-related costs and lower bad debt expense
- Lower interest expense of $700,000 (after tax), primarily due to lower average interest rates

Six Months Ended June 30, 2011 and 2010 Construction materials and contracting experienced an increased loss of $1.9 million. This increased loss was the result of:

- Lower earnings of $4.2 million (after tax), resulting from lower ready-mixed concrete margins and volumes and lower other product line margins, largely due to increased competition, less available work and weather-related delays, partially offset by higher asphalt volumes and margins
- Lower gains of $1.4 million (after tax) from the sale of property, plant and equipment
- Decreased construction margins of $1.3 million (after tax), primarily due to weather-related delays

Partially offsetting these items were:

- Lower income taxes of $2.5 million, primarily related to an income tax benefit related to favorable resolution of certain income tax matters

- Lower selling, general and administrative expense of $2.1 million (after tax), largely lower payroll-related costs
- Lower interest expense of $800,000 (after tax), as previously discussed

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,	
	2011	2010	2011	2010
	(In millions)			
Other:				
Operating revenues	$2.8	$2.3	$5.3	$4.5
Operation and maintenance	1.9	1.8	4.9	3.7
Depreciation, depletion and amortization	.4	.4	.7	.8
Taxes, other than income	—	.1	.1	.1
Intersegment transactions:				
Operating revenues	$45.5	$42.8	$99.3	$108.1
Purchased natural gas sold	34.3	36.8	81.2	95.8
Operation and maintenance	11.2	6.0	18.1	12.3

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 2010 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 2011, diluted, are projected in the range of $1.05 to $1.30. The Company expects the approximate percentage of 2011 earnings per common share by quarter to be:

  - Third quarter – 30 percent
  - Fourth quarter – 30 percent

- Although near term market conditions are uncertain, the Company's 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

- In April 2010, the Company filed an application with the NDPSC for an electric rate increase, as discussed in Note 17.

- In August 2010, the Company filed an application with the MTPSC for an electric rate increase, as discussed in Note 17.

- On July 7, 2011, the Company filed for an advance determination of prudence with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities, as discussed in Note 17.

- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors with company and customer owned pipeline facilities designed to serve existing facilities currently served by fuel oil or propane, and to serve new customers.

- The Company is currently involved with a number of pipeline looping projects to enhance the reliability and deliverability of its system in the Pacific Northwest.

- 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 market 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. The proposed project will total approximately $20 million and will include substation upgrades with construction expected to begin in the third quarter 2011. Its customers would not bear any of the costs associated with the project as costs will be recovered through an approved interconnect tariff. The NDPSC has approved the route permits for this project. The project is expected to be completed in the first quarter of 2012. A major market party to the wind farm project has announced its intentions to withdraw from the project which may affect development and timing of the associated power line by the Company.

- The South Dakota Board of Minerals and Environment has approved rules implementing the South Dakota Regional Haze Program that upon approval by the EPA will require the Big Stone Station to install and operate a BART air quality control system to reduce emissions of particulate matter, sulfur dioxide and nitrogen oxides as early as practicable, but not later than five years after EPA's approval of the state program. The state program was submitted January 21, 2011. The Company’s share of the cost of this air quality control system could exceed $100 million. At this time the Company believes continuing to operate Big Stone Station with the upgrade is the best option; however, it will continue to review alternatives. The Company intends to seek recovery of costs related to the above matter in electric rates charged to customers. On May 20, 2011, the Company filed for an advance determination of prudence with the NDPSC requesting advance determination that the air quality control system is reasonable and prudent, as discussed in Note 17.

Construction services

- Work backlog as of June 30, 2011, was approximately $364 million, compared to $389 million a year ago, and $347 million at March 31, 2011. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including refinery work.

- As a result of the continued slow economic recovery, the Company anticipates margins in 2011 to be comparable to 2010 levels.

- The Company is pursuing expansion in high-voltage transmission and substation construction, renewable resource construction, governmental facilities, refinery turnaround projects and utility service work.

- The Company continues to focus on costs and efficiencies to enhance margins. Selling, general and administrative expenses are down more than 30 percent for the trailing twelve months through June 30, 2011, compared to the annual expenses in 2008, the peak earnings year for this segment.

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

Pipeline and energy services

- 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 of North Dakota and eastern Montana. It owns an extensive natural gas pipeline system in the Bakken area. Ongoing energy development is expected to have many direct and indirect benefits to this business.

- The Company solicited customer interest in a 27 MMcf per day expansion of its existing natural gas pipeline in the Bakken production area in northwestern North Dakota in the first quarter of 2011. Sufficient customer interest was received to move forward on a project. Construction is underway and the capacity is projected to be in service in late third quarter of 2011.

- Final preparations are underway for the construction of approximately 12 miles of high pressure transmission pipeline providing takeaway capacity from Bear Paw Energy's Garden Creek processing facility being constructed in northwestern North Dakota. The pipeline project is expected to be completed in the fourth quarter of 2011.

- The Company has recently executed agreements to build approximately 13 miles of high pressure transmission pipeline from the Stateline I and II processing facilities in northwestern North Dakota to deliver gas into the Northern Border Pipeline. It has a projected completion date of mid 2012.

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

Natural gas and oil production

- Capital expenditures in 2011 are expected to be approximately $300 million. The Company continues its focus on returns by allocating a growing portion of its capital investment into the production of oil in the current commodity price environment. Its capital program reflects further exploitation of existing properties, acquisition of additional leasehold acreage, and exploratory drilling. The 2011 planned capital expenditure total does not include potential acquisitions of producing properties.

- For 2011, the Company expects a 1 percent to 5 percent increase in oil production offset by an 8 percent to 12 percent decrease in natural gas production, the result of extensive rain and flooding conditions that hampered operations in the Rocky Mountain region, as well as the deferral of some gas development activity because of sustained low natural gas prices. If natural gas prices recover, the Company believes it is positioned to spend additional capital on drilling its low cost natural gas properties.

- The Company added a second drilling rig in the Bakken early in the second quarter of 2011.

- Bakken – Mountrail County, North Dakota

  - The Company owns approximately 16,000 net acres of leaseholds targeting the middle Bakken and Three Forks formations. The drilling of 15 operated and participation in various non-operated wells is planned for 2011 with approximately $55 million of capital expenditures. Plans include drilling 17 wells or more annually in 2012 and 2013.

  - Over 50 future wells sites have been identified. Estimated gross ultimate recovery per well is 250,000 to 500,000 Bbls.

- Bakken – Stark County, North Dakota

  - The Company holds approximately 50,000 net exploratory leasehold acres, targeting the Three Forks formation. It anticipates drilling 3 operated wells on this acreage and participating in various non-operated wells in 2011 with capital of approximately $30 million.

  - Based on well results, the Company plans to drill 6 or more wells annually beginning in 2012.

  - Based on 640-acre spacing, the acreage holds over 75 potential drill sites. Estimated gross ultimate recovery rates per well are 250,000 to 400,000 Bbls.

- Bakken – Richland County, Montana

  - The Company recently acquired approximately 20,000 net exploratory leasehold acres, targeting the Three Forks formation.

- Niobrara – southeastern Wyoming

  - The Company holds approximately 65,000 net exploratory leasehold acres in this emerging oil play. It is completing seismic evaluation work on this acreage and expects to begin drilling 4 exploratory wells in 2011.

  - If successful, the Company plans to initiate a drilling program of approximately 8 wells annually starting in 2012.

  - The Company also expects to participate in various non-operated wells in the Niobrara.

  - The Company has more than 100 future locations on this acreage based on 640-acre spacing. Although this is an emerging exploratory play, early results by certain other

50

producers appear promising.

- Paradox Basin – Cane Creek Federal Unit, Utah
  - o The Company holds approximately 75,000 net exploratory leasehold acres.
  - o An Environmental Assessment for 9 wells was recently received by the Company.
  - o The Company is evaluating its drilling options.
- Texas
  - o The Company is targeting areas that have the potential for higher liquids content. It has approximately $50 million of capital targeted in 2011.
- Other Opportunities
  - o The Company holds approximately 80,000 net exploratory leasehold acres in the Heath Shale oil prospect in Montana. Plans include drilling 1 or 2 appraisal wells in 2011.
  - o The Company continues to pursue acquisitions of additional leaseholds. Approximately $50 million of capital has been allocated to leasehold acquisitions in 2011, focusing on expansion of existing positions and new opportunities.
- Earnings guidance reflects estimated natural gas and oil prices for August through December as follows:

Index*	Price Per Mcf/Bbl
Natural gas:	
NYMEX	$4.00 to $4.50
Ventura	$3.75 to $4.25
CIG	$3.75 to $4.25
Oil:	
NYMEX	$90.00 to $95.00

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

- For the last six months of 2011, the Company has hedged approximately 55 percent to 60 percent of its estimated natural gas production and 60 percent to 65 percent of its estimated oil production. For 2012, it has hedged 20 percent to 25 percent of its estimated natural gas production and 45 percent to 50 percent of its estimated oil production. The hedges that are in place as of August 1, 2011, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (MMBtu/Bbl)	Price (Per MMBtu/Bbl)
Natural Gas	Swap	HSC	7/11 - 12/11	680,800	$8.00
Natural Gas	Swap	NYMEX	7/11 - 12/11	2,024,000	$6.1027
Natural Gas	Swap	NYMEX	7/11 - 12/11	1,840,000	$5.4975
Natural Gas	Swap	NYMEX	7/11 - 12/11	1,840,000	$4.58
Natural Gas	Swap	NYMEX	7/11 - 12/11	1,840,000	$4.70
Natural Gas	Swap	NYMEX	7/11 - 12/11	1,840,000	$4.75
Natural Gas	Swap	NYMEX	7/11 - 10/11	1,230,000	$4.775
Natural Gas	Swap	Ventura	7/11 - 10/11	1,230,000	$4.365
Natural Gas	Swap	NYMEX	1/12 - 12/12	3,477,000	$6.27
Natural Gas	Swap	NYMEX	1/12 - 12/12	1,830,000	$5.005
Natural Gas	Swap	NYMEX	1/12 - 12/12	915,000	$5.005
Natural Gas	Swap	NYMEX	1/12 - 12/12	915,000	$5.0125
Natural Gas	Swap	Ventura	1/12 - 12/12	3,660,000	$4.87
Crude Oil	Collar	NYMEX	7/11 - 12/11	276,000	$80.00-$94.00
Crude Oil	Collar	NYMEX	7/11 - 12/11	184,000	$80.00-$89.00
Crude Oil	Collar	NYMEX	7/11 - 12/11	92,000	$77.00-$86.45
Crude Oil	Collar	NYMEX	7/11 - 12/11	92,000	$75.00-$88.00
Crude Oil	Swap	NYMEX	7/11 - 12/11	184,000	$81.35
Crude Oil	Swap	NYMEX	7/11 - 12/11	92,000	$85.85
Crude Oil	Put Option	NYMEX	7/11 - 12/11	184,000	$80.00*
Crude Oil	Call Option	NYMEX	7/11 - 12/11	184,000	$103.00*
Crude Oil	Collar	NYMEX	1/12 - 12/12	366,000	$80.00-$87.80
Crude Oil	Collar	NYMEX	1/12 - 12/12	366,000	$80.00-$94.50
Crude Oil	Collar	NYMEX	1/12 - 12/12	366,000	$80.00-$98.36
Crude Oil	Collar	NYMEX	1/12 - 12/12	183,000	$85.00-$102.75
Crude Oil	Collar	NYMEX	1/12 - 12/12	183,000	$85.00-$103.00
Crude Oil	Swap	NYMEX	1/12 - 12/12	183,000	$100.10
Crude Oil	Swap	NYMEX	1/12 - 12/12	183,000	$100.00
Crude Oil	Swap	NYMEX	1/12 - 12/12	366,000	$110.30
Crude Oil	Collar	NYMEX	1/13 - 12/13	182,500	$95.00-$117.00
Crude Oil	Collar	NYMEX	1/13 - 12/13	182,500	$95.00-$117.00
Natural Gas	Basis Swap	CIG	7/11 - 12/11	2,024,000	$0.395
Natural Gas	Basis Swap	Ventura	7/11 - 12/11	1,840,000	$0.15
Natural Gas	Basis Swap	Ventura	7/11 - 12/11	920,000	$0.15
Natural Gas	Basis Swap	Ventura	7/11 - 12/11	460,000	$0.16
Natural Gas	Basis Swap	Ventura	7/11 - 12/11	1,840,000	$0.16
Natural Gas	Basis Swap	Ventura	7/11 - 12/11	2,300,000	$0.155
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

* Deferred premium of $4.00. Put option was purchased. Call option was sold.

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, 2011, was approximately $649 million, with 93 percent of construction backlog being public work and private representing 7 percent. In the Company's peak earnings year of 2006, private backlog represented 40 percent of construction backlog. Backlog a year ago was $677 million. Total backlog at March 31, 2011, was $569 million.

- Examples of projects in work backlog include several highway paving projects, airports, bridge work, reclamation and harbor expansion projects.

- The Company is part of a joint venture that was selected as the low bidder on the Port of Long Beach expansion. Its share of the project for this phase is expected to exceed $25 million. The Company has green fielded an operation in Williston, North Dakota and was recently awarded a $33 million highway project in the Bakken area of North Dakota. It also expects to place a new asphalt oil terminal into service in late 2011 in Wyoming.

- As a result of the continued slow recovery in the residential and commercial markets and uncertainty in federal and state transportation funding, the Company expects overall 2011 volumes to be comparable to 2010.

- Federal transportation stimulus of $7.9 billion was directed to states where the Company operates. Of that amount, 74 percent was spent as of June 30, 2011, with the majority of the remaining $2.0 billion to be spent during the remainder of 2011.

- The Company is the primary cement provider and has the opportunity to supply a portion of the ready-mixed concrete and aggregate related to a multi-phased light rail project in Hawaii.

- 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 more than 40 percent for the trailing twelve months through June 30, 2011, compared to the annual expenses in 2006, the peak earnings year for this segment.

- As the country's 5th 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 nine labor contracts that Knife River was negotiating, as reported in Items 1 and 2 – Business and Properties – General in the 2010 Annual Report, six have been ratified. The three remaining contracts are still in negotiations.

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Note 7, which is incorporated by reference.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

The Company's critical accounting policies involving significant estimates include impairment testing of natural gas and oil production properties, impairment testing of long-lived assets and intangibles,

53

revenue recognition, 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 2010 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2010 Annual Report.

LIQUIDITY AND CAPITAL COMMITMENTS
At June 30, 2011, the Company had cash and cash equivalents of $107.8 million and available capacity of $619.7 million under the outstanding credit facilities of the Company and its subsidiaries.

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 2011 increased $50.9 million from the comparable period in 2010. The increase was largely due to lower working capital requirements of $32.1 million, largely at the electric and natural gas distribution businesses, as well as higher deferred income taxes of $25.2 million, largely the result of higher bonus depreciation.

Investing activities Cash flows used in investing activities in the first six months of 2011 decreased $112.0 million from the comparable period in 2010. The decrease was largely due to lower cash used for acquisitions of $106.4 million, primarily at the natural gas and oil production business.

Financing activities Cash flows used in financing activities in the first six months of 2011 increased $168.2 million from the comparable period in 2010 largely resulting from the higher repayment of long-term debt and short-term borrowings, as well as lower issuance of long-term debt.

Defined benefit pension plans
There were no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2010 Annual Report. For further information, see Note 16 and Part II, Item 7 in the 2010 Annual Report.

Capital expenditures
Net capital expenditures for the first six months of 2011 were $199.2 million and are estimated to be approximately $570 million for 2011. Estimated capital expenditures include:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering projects
- Further development of existing properties, acquisition of additional leasehold acreage and exploratory drilling at the natural gas and oil production segment
- Power generation opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- 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 2011 capital expenditures referred to previously. The Company expects the 2011 estimated capital expenditures to be funded in their entirety with cash flow generated from operations.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed later, 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, 2011. 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 2010 Annual Report.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries at June 30, 2011:

Company	Facility	Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date	
		(Dollars in millions)							
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$100.0		$—	(b)	$—		5/26/15	
Cascade Natural Gas Corporation	Revolving credit agreement	$50.0	(c)	$—		$1.9	(d)	12/28/12	(e)
Intermountain Gas Company	Revolving credit agreement	$65.0	(f)	$—		$—		8/11/13	
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (g)	$400.0		$6.0	(b)	$24.9	(d)	12/13/12	
Williston Basin Interstate Pipeline Company	Uncommitted long-term private shelf agreement	$125.0		$87.5		$—		12/23/11	(h)

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 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) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letters of credit, as discussed in Note 18, reduce amounts available under the credit agreement.
(e) Provisions allow for an extension of up to two years upon consent of the banks.
(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(g) 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.
(h) Represents expiration of the ability to borrow additional funds under the agreement.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. 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 preceding table.

MDU Resources Group, Inc. On May 26, 2011, the Company entered into a new revolving credit agreement, which replaces the revolving credit agreement that expired on June 21, 2011. The credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments. The credit agreement does not contain any cross-default provisions.

56

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 4.0 times and 4.1 times for the 12 months ended June 30, 2011 and December 31, 2010, respectively.

Common stockholders' equity as a percent of total capitalization was 66 percent and 64 percent at June 30, 2011 and December 31, 2010, respectively. This ratio is calculated as the Company's common stockholders' equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus stockholders' equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

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. This agreement terminated on May 28, 2011.

On May 19, 2011, the Company filed a shelf registration statement with the SEC, pursuant to Rule 415 under the Securities Act, under which the Company may issue and sell any combination of common stock and debt securities. 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. The Company's board of directors currently has authorized the issuance and sale of up to an aggregate of $1.0 billion worth of such securities. The Company's board of directors reviews this authorization on a periodic basis and the aggregate amount of securities authorized may be increased in the future.

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 the Brazilian Transmission Lines, Centennial has agreed to 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 sale of the Brazilian Transmission Lines.

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

Contractual obligations and commercial commitments

There are no material changes in the Company's contractual obligations relating to long-term debt, estimated interest payments, operating leases, purchase commitments and minimum funding requirements for its defined benefit plans for 2011 from those reported in the 2010 Annual Report.

For more information on the Company's uncertain tax positions, see Note 14.

For more information on contractual obligations and commercial commitments, see Part II, Item 7 in the 2010 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 utilizes, and Intermountain periodically utilizes, 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 2010 Annual Report, and Notes 8 and 12.

The following table summarizes derivative agreements entered into by Fidelity and Cascade as of June 30, 2011. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade 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 2011	$ 5.19	12,525	$ 9,191
Natural gas swap agreements maturing in 2012	$ 5.37	10,797	$ 6,005
Natural gas basis swap agreements maturing in 2011	$ .21	9,384	$ (1,328)
Natural gas basis swap agreements maturing in 2012	$ .41	3,477	$ (224)
Oil swap agreements maturing in 2011	$ 82.85	276	$ (3,874)
Oil swap agreements maturing in 2012	$ 105.18	732	$ 3,740
Cascade			
Natural gas swap agreement maturing in 2011	$ 6.67	371	$ (902)
Natural gas swap agreements maturing in 2012	$ 4.47	305	$ 11

	Weighted Average Floor/Ceiling Price (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Fidelity			
Oil collar agreements maturing in 2011	$78.86/$90.64	644	$ (5,370)
Oil collar agreements maturing in 2012	$81.25/$95.88	1,464	$ (13,166)
Oil collar agreements maturing in 2013	$95.00/$117.00	365	$ 1,363

	Deferred Premium	Weighted Average Floor (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value

Fidelity				
Oil put agreement maturing in 2011	$4.00	$ 80.00	184	$ (547)
Oil call agreement maturing in 2011	$4.00	$ 103.00	184	$ 179

Interest rate risk

There were no material changes to interest rate risk faced by the Company from those reported in the 2010 Annual Report. For more information, see Part II, Item 7A in the 2010 Annual Report.

At June 30, 2011 and 2010, and December 31, 2010, the Company had no outstanding interest rate hedges.

Foreign currency risk
The Company's equity method investment in ECTE is 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 2010 Annual Report.

At June 30, 2011 and 2010, and December 31, 2010, 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) under the Exchange Act. The Company's disclosure 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 management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer 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
No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended June 30, 2011, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see Note 18, which is incorporated by reference.

ITEM 1A. RISK FACTORS

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

60

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 2010 Annual Report other than the risk related to environmental laws and regulations; the risk associated with electric generation operation that could be adversely impacted by global climate change initiatives to reduce GHG emissions; and the risk related to increased costs related to obligations under multiemployer pension plans. 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 operations are subject to environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

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

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

The EPA has issued draft regulations that outline several possible approaches for coal combustion residuals management under the RCRA. One approach, designating coal ash as a hazardous waste would significantly change and increase the costs of managing coal ash at five plants that supply electricity to customers of Montana-Dakota. This designation also could significantly increase costs for Knife River, which beneficially uses fly ash as a cement replacement in ready-mixed concrete and road base applications.

The EPA has also proposed rules to reduce mercury and other air toxics emissions from coal- and oil-fired electric utility steam generating units. As proposed, air pollution control retrofits, such as baghouses, would need to be installed at company owned electric generation facilities in order to comply with the rule's emissions limits. Montana-Dakota is currently evaluating the impact of the proposed rule on its electric generation resources.

Hydraulic fracturing is an important common practice used by the Company that involves injecting water, sand and chemicals under pressure into rock formations to stimulate natural gas and oil production. The EPA is developing a study to review the potential effects of hydraulic fracturing on underground sources of drinking water; the results of that study have the potential to impact the likelihood or scope of future legislation or regulation. Other legislative initiatives and regulatory studies, proceedings or initiatives at federal or state agencies focused on the hydraulic fracturing process could result in additional compliance, reporting and disclosure requirements. While not materially impacted by current regulation, future legislation or regulation could cause the Company to experience increased compliance and operating costs, as well as delay or inhibit its ability to develop its natural gas and oil reserves.

Global climate change initiatives to reduce GHG emissions could adversely impact the Company's electric generation operations.

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. The EPA finalized its endangerment finding for GHG emissions in late 2009, and its GHG "Tailoring" Rule in 2010. Starting in 2011, the GHG "Tailoring" Rule will require new large emission sources, such as coal-fired electric generating facilities, and existing large emission sources that make modifications that increase GHG emission to obtain permits and conduct best available control technology evaluations to limit the amount of GHG emission from these sources.

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. Approximately 70 percent of Montana-Dakota's owned generating capacity and more than 90 percent of the electricity it generates is from coal-fired plants. Montana-Dakota also owns approximately 100 MW of natural gas- and oil-fired peaking plants.

While the future of GHG regulation is uncertain, Montana-Dakota's electric generating facilities may be subject to 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 expanded energy conservation efforts or increased development of renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs. If Montana-Dakota does not receive timely and full recovery of GHG emission compliance costs from its customers, then such costs could have an adverse impact on the results of its operations.

Due to the uncertain availability of technologies to control GHG emissions and the unknown obligations that potential GHG emission legislation or regulations may create, the Company cannot determine the financial impact on its operations.

Other Risks
An increase in costs related to obligations under multiemployer pension plans could have a material negative effect on the Company's results of operations and cash flows.

Various operating subsidiaries of the Company participate in approximately 65 multiemployer pension plans for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.

The Company may be obligated to increase its contributions to underfunded plans that are classified as being in endangered, seriously endangered, or critical status as defined by the Pension Protection Act of 2006. Plans classified as being in one of these statuses are required to adopt rehabilitation plans or funding improvement plans to improve their funded status through increased contributions, reduced benefits or a combination of the two. Based on available information, the Company believes approximately 35 of the multiemployer plans to which it contributes are currently in endangered, seriously endangered, or critical status.

The Company may also be required to increase its contributions to multiemployer plans where the other participating employers in such plans withdraw from the plan and are not able to contribute an amount sufficient to fund the unfunded liabilities associated with their participants in the plans. The amount and timing of any increase in the Company's required contributions to multiemployer pension plans may also depend upon one or more of the following factors including the outcome of collective bargaining, actions taken by trustees who manage the plans, the industry for which contributions are made, future determinations that additional plans reach endangered, seriously endangered or critical status, government regulations and the actual return on assets held in the plans, among others. The Company may experience increased operating expenses as a result of the required contributions to multiemployer pension plans, which may have a material adverse effect on the Company's financial condition, results of operations or cash flows.

In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan to the extent these plans are underfunded.

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

None.

ITEM 5. OTHER INFORMATION

MINE SAFETY INFORMATION

This mine safety information is reported pursuant to the Dodd-Frank Act. The Dodd-Frank Act requires reporting of the following types of citations or orders:

1. Citations issued under section 104(a) of the Mine Safety Act for violations that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard.
2. Orders issued under section 104(b) of the Mine Safety Act. Orders are issued under this section when citations issued under section 104(a) have not been totally abated within the time period allowed by the citation or subsequent extensions.
3. Citations or orders issued under section 104(d) of the Mine Safety Act. Citations or orders are issued under this section when it has been determined that the violation is caused by an unwarrantable failure of the mine operator to comply with the standards. An unwarrantable failure occurs when the mine operator is deemed to have engaged in aggravated conduct constituting more than ordinary negligence.
4. Citations issued under Section 110(b)(2) of the Mine Safety Act for flagrant violations. Violations are considered flagrant for repeat or reckless failures to make reasonable efforts to eliminate a known violation of a mandatory health and safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury.
5. Imminent danger orders issued under Section 107(a) of the Mine Safety Act. An imminent danger is defined as the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated.
6. Notice received under Section 104(e) of the Mine Safety Act of a pattern of violations or the potential to have such a pattern of violations that could significantly and substantially contribute to the cause and effect of mine health and safety standards.

During the three months ended June 30, 2011, none of the Company's operating subsidiaries received citations or orders under the following sections of the Mine Safety Act: 104(b), 104(d), 110(b)(2) or 104(e). In addition, the Company did not have any mining-related fatalities during this period. The Company has 77 contests pending before administrative law judges of the Federal Mine Safety and Health Review Commission that involve all types of citations. Of the contests pending, 24 were initiated during the three months ended June 30, 2011.

Information related to citations and assessments under the Mine Safety Act during the three months ended June 30, 2011, is shown in the following table. Proposed assessments listed could have arisen from citations issued in prior periods. In addition, assessments may not have yet been proposed for citations issued during the period for which data is reported and could relate to citations not reportable under the Dodd-Frank Act. Amounts shown as outstanding as of June 30, 2011, include amounts assessed for all citations issued under the Mine Safety Act, including those not reportable under the Dodd-Frank Act.

Mine	State	Section 104(a) Citations Issued	Section 107(a) Citations Issued	Citations Contested	Proposed Assessments Levied	Outstanding as of June 30, 2011
Klatt Terminal	AK	2	—	—	$ —	$—
Concrete, Inc.	CA	—	—	—	263	—
Hallwood Plant	CA	1	—	2	—	—
Orland Plant	CA	3	—	8	—	—
Pebbly Beach Quarry	CA	4	1	4	2,015	1,815
Vernalis	CA	—	—	—	100	—
Halawa Valley	HI	—	—	—	815	22,490
Kona Sand Plant	HI	—	—	—	100	—
Portable 1	HI	3	—	—	1,306	—
Portable 2	HI	—	—	—	300	—
Puunene Quarry	HI	—	—	—	—	660
Waikapu Quarry	HI	2	1	—	200	100
Waimea Quarry	HI	—	—	—	—	238
Becker Wash Plant #1	IA	2	—	—	—	—
Crusher #1	ID	—	—	—	200	100
Anderson Pit	MN	1	—	—	—	—
Kalispell Wash Plant	MT	2	—	—	—	—
Portable Crusher #1	MT	1	—	—	—	—
Dralle Pit	ND	—	—	—	200	—
McKenzie Pit	ND	1	—	—	—	—
Pioneer	ND	2	—	—	—	18,500
Wienmann Pit	ND	—	—	—	2,104	—
Coffee Lake	OR	—	—	—	100	—
Coffin Butte	OR	—	—	—	300	—
Eugene	OR	—	—	—	100	—
Fisher Island	OR	—	—	—	723	—
Gresham S & G	OR	1	—	—	625	—
Kirkland	OR	—	—	—	300	—
Lone Pine Portable	OR	—	—	—	—	100
Paetsch Pit	OR	—	—	—	—	112
Salem-Reed Pit	OR	—	—	4	794	478
Sullivan Quarry MC1	OR	2	—	—	200	200
Watters Quarry	OR	—	—	—	100	—
Sky High Pit	TX	2	—	1	—	—
Star Pit #1	WY	1	—	5	700	500
Total		30	2	24	$ 11,545	$45,293

The Dodd-Frank Act also requires information to be disclosed about each citation contested before the Federal Mine Safety and Health Review Commission during the time period covered by the periodic report. Please refer to the following table for the required information since enactment of the Dodd-Frank Act through June 30, 2011.

Mine	State	Month Citation Issued		Contest Initiated By	Category of Violation		Proposed Assessments Levied (Dollars)*	Month Citation Closed**	Result of Contest**
Hallwood Plant	CA	4/2011	***	Operator	104	(a)	$ 100	—	—
Hallwood Plant	CA	4/2011	***	Operator	104	(a)	1,304	—	—
Orland Plant	CA	4/2011	***	Operator	104	(a)	—	—	—
Orland Plant	CA	4/2011	***	Operator	104	(a)	—	—	—
Orland Plant	CA	4/2011	***	Operator	104	(a)	—	—	—
Orland Plant	CA	4/2011	***	Operator	104	(a)	—	—	—
Orland Plant	CA	4/2011	***	Operator	104	(a)	—	—	—
Orland Plant	CA	4/2011	***	Operator	104	(a)	—	—	—
Orland Plant	CA	4/2011	***	Operator	104	(a)	—	—	—
Orland Plant	CA	4/2011	***	Operator	104	(a)	—	—	—
Pebbly Beach	CA	5/2011	***	Operator	104	(a)	555	—	—
Pebbly Beach	CA	5/2011	***	Operator	104	(a)	555	—	—
Pebbly Beach	CA	5/2011	***	Operator	104	(a)	555	—	—
Pebbly Beach	CA	5/2011	***	Operator	107	(a)	—	—	—
Waikapu Quarry	HI	2/2011		Operator	104	(a)	100	5/2011	No Change
Waikapu Quarry	HI	2/2011		Operator	104	(a)	117	5/2011	No Change
Little Falls	MN	10/2010		Operator	104	(a)	100	1/2011	No Change
Little Falls	MN	11/2010		Operator	104	(a)	100	1/2011	No Change
Rittenour Pit	MN	10/2010		Operator	104	(a)	100	4/2011	No Change
Rittenour Pit	MN	10/2010		Operator	104	(a)	100	4/2011	No Change
Rittenour Pit	MN	10/2010		Operator	104	(a)	362	4/2011	No Change
Rockville 3	MN	11/2010		Operator	104	(d)	2,400	—	—
T Olson Pit	MN	10/2010		Operator	104	(a)	392	6/2011	Vacated
T Olson Pit	MN	10/2010		Operator	104	(a)	100	6/2011	Reduced
T Olson Pit	MN	10/2010		Operator	104	(a)	100	6/2011	Reduced
Bender Pit	ND	8/2010		Operator	104	(a)	162	4/2011	No Change
Bender Pit	ND	8/2010		Operator	104	(a)	100	4/2011	No Change
Lone Pine	OR	7/2010		Operator	104	(a)	100	—	—
Paetsch Pit	OR	12/2010		Operator	104	(a)	112	—	—
Paetsch Pit	OR	1/2011		Operator	104	(b)	—	—	—

Quality Rock	OR	11/2010		Operator	104	(d)	—	—	—
Quality Rock	OR	11/2010		Operator	104	(d)	—	—	—
Quality Rock	OR	11/2010		Operator	104	(d)	—	—	—
Salem-Reed Pit	OR	2/2011	***	Operator	104	(a)	108	—	—
Salem-Reed Pit	OR	2/2011	***	Operator	104	(a)	162	—	—
Salem-Reed Pit	OR	2/2011	***	Operator	104	(a)	108	—	—
Salem-Reed Pit	OR	2/2011	***	Operator	104	(a)	100	—	—
Sky High Pit	TX	1/2011	****	Operator	104	(a)	424	—	—
Star Pit #1	WY	3/2011	***	Operator	104	(a)	100	—	—
Star Pit #1	WY	3/2011	***	Operator	104	(a)	100	—	—

66

Star Pit #1	WY	4/2011	***	Operator	104	(a)	100	—	—
Star Pit #1	WY	4/2011	***	Operator	104	(a)	100	—	—
Star Pit #1	WY	4/2011	***	Operator	104	(a)	100	—	—
VR Pit	WY	11/2010		Operator	104	(a)	100	—	—

*Assessments may not have yet been proposed for citations issued during the period for which the data is reported.

**Results of citations contested will be reported as one of the following: Vacated – the citation was dropped; Reduced – the severity of the violation and/or the proposed assessment amount was reduced; or No Change – the citation was enforced as issued.

***Contest initiated during the three months ended June 30, 2011.

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 5, 2011	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)	Non-Employee Director Stock Compensation Plan, as amended May 12, 2011
+10(b)	Directors' Compensation Policy, as amended May 12, 2011
+10(c)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of June 30, 2011
+10(d)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2011
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, 2011, 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 in summary and detail

+ 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.