

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

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

FORM 10-Q

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

For The Quarterly Period Ended March 31, 2011

OR

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

For the Transition Period from _____ to _____

Commission file number 1-3480

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

Delaware
(State or other jurisdiction of incorporation
or organization)

41-0423660
(I.R.S. Employer Identification No.)

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

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

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

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 ☒ No ☐.

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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 ☒

Accelerated filer ☐

Non-accelerated filer ☐

Smaller reporting company ☐

(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 ☐ No ☒.

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of April 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
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	Empresa Catarinense de Transmissão de Energia S.A. (10.01 percent ownership interest at March 31, 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

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
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
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
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 Utilities Commission

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
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.

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PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended March 31,	
	2011	2010
	(In thousands, except per share amounts)	
Operating revenues:		
Electric, natural gas distribution and pipeline and energy services	\$477,481	\$460,245
Construction services, natural gas and oil production, construction materials and contracting, and other	424,324	374,532
Total operating revenues	901,805	834,777
Operating expenses:		
Fuel and purchased power	16,954	16,911
Purchased natural gas sold	244,686	233,691
Operation and maintenance:		
Electric, natural gas distribution and pipeline and energy services	67,963	62,987
Construction services, natural gas and oil production, construction materials and contracting, and other	359,797	313,786
Depreciation, depletion and amortization	84,674	78,678
Taxes, other than income	49,665	45,795
Total operating expenses	823,739	751,848
Operating income	78,066	82,929
Earnings from equity method investments	484	2,183
Other income	1,900	2,502
Interest expense	22,017	20,516
Income before income taxes	58,433	67,098
Income taxes	15,904	25,326
Income from continuing operations	42,529	41,772
Income from discontinued operations, net of tax (Note 9)	448	—
Net income	42,977	41,772
Dividends on preferred stocks	171	172
Earnings on common stock	\$42,806	\$41,600

Earnings per common share – basic:		
Earnings before discontinued operations	\$.22	\$.22
Discontinued operations, net of tax	.01	—
Earnings per common share -- basic	\$.23	\$.22
Earnings per common share – diluted:		
Earnings before discontinued operations	\$.22	\$.22
Discontinued operations, net of tax	.01	—
Earnings per common share -- diluted	\$.23	\$.22
Dividends per common share		
	\$.1625	\$.1575
Weighted average common shares outstanding -- basic		
	188,671	187,963
Weighted average common shares outstanding -- diluted		
	188,815	188,220

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

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

December
31,
2010

March 31,
2010

March 31,
2011

(In thousands, except shares and per share amounts)

ASSETS

Current assets:

Cash and cash equivalents	\$ 136,016	\$ 106,664	\$ 222,074
Receivables, net	533,279	467,790	583,743
Inventories	262,696	253,931	252,897
Deferred income taxes	45,206	18,543	32,890
Commodity derivative instruments	13,250	38,146	15,123
Prepayments and other current assets	73,556	104,687	60,441
Total current assets	1,064,003	989,761	1,167,168
Investments	117,015	141,443	103,661
Property, plant and equipment	7,271,173	6,875,397	7,218,503
Less accumulated depreciation, depletion and amortization	3,174,654	2,935,453	3,103,323
Net property, plant and equipment	4,096,519	3,939,944	4,115,180
Deferred charges and other assets:			
Goodwill	634,931	634,633	634,633
Other intangible assets, net	24,351	26,612	25,271
Other	254,472	249,454	257,636
Total deferred charges and other assets	913,754	910,699	917,540
Total assets	\$ 6,191,291	\$ 5,981,847	\$ 6,303,549

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities:

Short-term borrowings	\$ —	\$ 7,700	\$ 20,000
Long-term debt due within one year	12,785	72,572	72,797
Accounts payable	267,922	241,465	301,132
Taxes payable	49,852	69,077	56,186
Dividends payable	30,850	29,796	30,773
Accrued compensation	25,774	22,607	40,121
Commodity derivative instruments	40,499	32,328	24,428
Other accrued liabilities	227,088	187,368	222,639
Total current liabilities	654,770	662,913	768,076
Long-term debt	1,414,077	1,426,146	1,433,955
Deferred credits and other liabilities:			
Deferred income taxes	701,933	603,803	672,269
Other liabilities	731,428	680,965	736,447
Total deferred credits and other liabilities	1,433,361	1,284,768	1,408,716
Commitments and contingencies			
Stockholders' equity:			
Preferred stocks	15,000	15,000	15,000
Common stockholders' equity:			
Common stock			
	189,332	188,656	188,901

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Shares issued -- \$1.00 par value, 189,332,485 at March 31, 2011,
188,656,012 at March 31, 2010 and 188,901,379 at December 31, 2010

Other paid-in capital	1,032,040	1,018,441	1,026,349
Retained earnings	1,509,449	1,388,914	1,497,439
Accumulated other comprehensive income (loss)	(53,112)	635	(31,261)
Treasury stock at cost – 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,674,083	2,593,020	2,677,802
Total stockholders' equity	2,689,083	2,608,020	2,692,802
Total liabilities and stockholders' equity	\$6,191,291	\$5,981,847	\$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)

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
Operating activities:		
Net income	\$42,977	\$41,772
Income from discontinued operations, net of tax	448	—
Income from continuing operations	42,529	41,772
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	84,674	78,678
Earnings, net of distributions, from equity method investments	(484)	(1,443)
Deferred income taxes	34,502	8,226
Changes in current assets and liabilities, net of acquisitions:		
Receivables	50,260	61,914
Inventories	(13,634)	(6,198)
Other current assets	(18,897)	(34,546)
Accounts payable	(21,875)	(34,795)
Other current liabilities	(15,738)	(21,733)
Other noncurrent changes	(20,510)	(6,759)
Net cash provided by continuing operations	120,827	85,116
Net cash used in discontinued operations	(366)	—
Net cash provided by operating activities	120,461	85,116
Investing activities:		
Capital expenditures	(82,664)	(123,902)
Acquisitions, net of cash acquired	(157)	(1,725)
Net proceeds from sale or disposition of property	10,524	1,936
Investments	(9,856)	1,404
Net cash used in continuing operations	(82,153)	(122,287)
Net cash provided by discontinued operations	—	—
Net cash used in investing activities	(82,153)	(122,287)
Financing activities:		
Repayment of short-term borrowings	(20,000)	(2,600)
Repayment of long-term debt	(80,630)	(479)
Proceeds from issuance of common stock	5,744	1,214
Dividends paid	(30,773)	(29,749)
Excess tax benefit on stock-based compensation	1,248	452
Net cash used in continuing operations	(124,411)	(31,162)
Net cash provided by discontinued operations	—	—
Net cash used in financing activities	(124,411)	(31,162)
Effect of exchange rate changes on cash and cash equivalents	45	(117)
Decrease in cash and cash equivalents	(86,058)	(68,450)
Cash and cash equivalents -- beginning of year	222,074	175,114
Cash and cash equivalents -- end of period	\$136,016	\$106,664

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

March 31, 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 March 31, 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 \$33.9 million and \$21.6 million as of March 31, 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 March 31, 2011 and 2010, and December 31, 2010, was \$16.4 million, \$17.1 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:

	March 31, 2011	March 31, 2010	December 31, 2010
	(In thousands)		
Aggregates held for resale	\$ 82,086	\$ 81,074	\$ 79,894
Materials and supplies	61,788	58,573	57,324
Natural gas in storage (current)	11,953	10,741	34,557
Merchandise for resale	31,830	29,371	30,182
Asphalt oil	51,506	50,423	25,234
Other	23,533	23,749	25,706
Total	\$ 262,696	\$ 253,931	\$ 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 March 31, 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 months ended March 31, 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:

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
Interest, net of amount capitalized	\$ 25,579	\$ 25,159
Income taxes	\$ 9,981	\$ 5,424

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 does 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 March 31,	
	2011	2010
	(In thousands)	
Net income	\$ 42,977	\$ 41,772
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 \$(13,109) and \$13,159 in 2011 and 2010, respectively	(21,848)	21,471
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of \$137 and \$(573) in 2011 and 2010, respectively	230	(934)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(22,078)	22,405
Foreign currency translation adjustment, net of tax of \$137 and \$(621) in 2011 and 2010, respectively	211	(937)
Net unrealized gains on available-for-sale investments, net of tax of \$9 in 2011	16	—
	(21,851)	21,468
Comprehensive income	\$ 21,126	\$ 63,240

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 March 31, 2011, include the Brazilian Transmission Lines.

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 and recognized a gain of \$22.7 million (\$13.8 million after tax) which was recorded in earnings from equity method investments on the Consolidated Statements of Income. The Company's entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE was sold. 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 March 31, 2011 and 2010, and December 31, 2010, the Company's equity method investments had total assets of \$108.2 million, \$374.8 million and \$107.4 million, respectively, and long-term debt of \$46.3 million, \$166.4 million and \$30.1 million, respectively. The Company's investment in its equity method investments was approximately \$11.7 million, \$56.0 million and \$10.9 million, including undistributed earnings of \$2.4 million, \$10.8 million and \$1.9 million, at March 31, 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:

Three Months Ended	Balance as of January 1,	Goodwill Acquired During the	Balance as of March 31,
March 31, 2011	2011*	Year**	2011*
	(In thousands)		
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 purchase price adjustments that were not material related to acquisitions in a prior period.

Three Months Ended	Balance as of January 1,	Goodwill Acquired During the	Balance as of March 31,
March 31, 2010	2010*	Year**	2010*
	(In thousands)		
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.

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:

	March 31, 2011	March 31, 2010	December 31, 2010
	(In thousands)		
Customer relationships	\$ 21,702	\$ 24,942	\$ 24,942
Accumulated amortization	(8,890)	(10,093)	(11,625)
	12,812	14,849	13,317
Noncompete agreements	7,685	9,405	9,405
Accumulated amortization	(4,898)	(5,755)	(6,425)
	2,787	3,650	2,980
Other	12,899	11,368	13,217
Accumulated amortization	(4,147)	(3,255)	(4,243)
	8,752	8,113	8,974
Total	\$ 24,351	\$ 26,612	\$ 25,271

Amortization expense for amortizable intangible assets for the three months ended March 31, 2011 and 2010, was \$900,000 and \$1.0 million, respectively. Estimated amortization expense for amortizable intangible assets is \$4.1 million in 2011, \$4.0 million in 2012, \$3.8 million in 2013, \$3.2 million in 2014, \$2.6 million in 2015 and \$7.6 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 March 31, 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 March 31, 2011, Cascade held natural gas swap agreements, with total forward notional volumes of 920,000 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 months ended March 31, 2011, Cascade recorded the change in the fair market value of the derivative instruments of \$6.6 million as a decrease to regulatory assets. For the three months ended March 31, 2010, Cascade and Intermountain recorded the change in the fair market value of the derivative instruments of \$5.1 million 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 March 31, 2011, was \$2.8 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 March 31, 2011, was \$2.8 million.

Fidelity

At March 31, 2011, Fidelity held natural gas swap agreements with total forward notional volumes of 29.8 million MMBtu, natural gas basis swap agreements with total forward notional volumes of 17.5 million MMBtu, and oil swap, collar and put option agreements with total forward notional volumes of 3.5 million Bbl, all of which were designated as cash flow hedging instruments. At March 31, 2011, Fidelity held an oil call option agreement with total forward notional volumes of 275,000 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.

Excluding the oil call option agreement, which was not designated as a hedge, the amount of hedge ineffectiveness was immaterial for the three months ended March 31, 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 loss on the derivative instrument that did not qualify for hedge accounting was reported in operating revenues on the Consolidated Statements of Income and was \$1.7 million (before tax) for the three months ended March 31, 2011.

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 March 31, 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 21 months. The Company estimates that over the next 12 months net losses of approximately \$14.2 million (after tax) will be reclassified from accumulated other comprehensive 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 March 31, 2011, was \$55.8 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 March 31, 2011, was \$55.8 million.

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

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at March 31, 2011	Fair Value at March 31, 2010	Fair Value at December 31, 2010
(In thousands)				
Designated as hedges	Commodity derivative instruments	\$ 13,250	\$ 38,146	\$ 15,123
	Other assets – noncurrent	3,148	6,960	4,104
		16,398	45,106	19,227
Not designated as hedges	Commodity derivative instruments	—	—	—
	Other assets – noncurrent	—	—	—
		—	—	—
Total asset derivatives		\$ 16,398	\$ 45,106	\$ 19,227

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at March 31, 2011	Fair Value at March 31, 2010	Fair Value at December 31, 2010
(In thousands)				
Designated as hedges	Commodity derivative instruments	\$ 35,990	\$ 11,616	\$ 15,069
	Other liabilities – noncurrent	18,082	759	6,483
		54,072	12,375	21,552
Not designated as hedges	Commodity derivative instruments	4,509	20,712	9,359
	Other liabilities – noncurrent	—	2,061	—
		4,509	22,773	9,359
Total liability derivatives		\$ 58,581	\$ 35,148	\$ 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 \$41.6 million, \$36.5 million and \$39.5 million, as of March 31, 2011 and 2010, and December 31, 2010, respectively, are classified as Investments on the Consolidated Balance Sheets. The increase in the fair value of these investments for the three months ended March 31, 2011 and 2010, was \$2.1 million (before tax) and \$1.7 million (before tax), respectively. The change in fair value, which is

considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option for its remaining available-for-sale securities, which 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 March 31, 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. The Company's mortgage-backed securities and U.S. Treasury securities had unrealized gains of \$16,000 (after tax) for the three months ended March 31, 2011, which were recorded in accumulated other comprehensive loss on the Consolidated Balance Sheet.

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 March 31, 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 March 31, 2011
	(In thousands)			
Assets:				
Money market funds	\$ —	\$ 75,658	\$ —	\$ 75,658
Available-for-sale securities:				
Insurance investment contract*	—	41,594	—	41,594
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,064	—	8,064
U.S. Treasury securities	—	1,720	—	1,720
Commodity derivative instruments – current	—	13,250	—	13,250
Commodity derivative instruments – noncurrent	—	3,148	—	3,148
Total assets measured at fair value	\$ —	\$ 154,834	\$ —	\$ 154,834
Liabilities:				
Commodity derivative instruments – current	\$ —	\$ 40,499	\$ —	\$ 40,499
Commodity derivative instruments – noncurrent	—	18,082	—	18,082
Total liabilities measured at fair value	\$ —	\$ 58,581	\$ —	\$ 58,581

* 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
March 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 March 31, 2010
(In thousands)				
Assets:				
Money market funds	\$ 10,977	\$ 65,000	\$ —	\$ 75,977
Available-for-sale securities:				
Fixed-income securities	2,785	11,400	—	14,185
Equity securities	6,689	—	—	6,689
Insurance investment contract*	—	27,000	—	27,000
Commodity derivative instruments				
– current	—	38,146	—	38,146
Commodity derivative instruments				
– noncurrent	—	6,960	—	6,960
Total assets measured at fair value	\$ 20,451	\$ 148,506	\$ —	\$ 168,957
Liabilities:				
Commodity derivative instruments				
– current	\$ —	\$ 32,328	\$ —	\$ 32,328
Commodity derivative instruments				
– noncurrent	—	2,820	—	2,820
Total liabilities measured at fair value	\$ —	\$ 35,148	\$ —	\$ 35,148

* 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

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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 1 available-for-sale securities is determined using the market approach and is based on quoted market prices in active markets for identical equity and fixed-income securities.

The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions, 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 months ended March 31, 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 March 31, 2011	\$ 1,426,862	\$ 1,526,923
Long-term debt at March 31, 2010	\$ 1,498,718	\$ 1,586,765
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.

15. Business segment data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences

in products, services and regulation. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of Centennial Resources' equity method investment in the Brazilian Transmission Lines.

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

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment.

The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes Centennial Resources' equity method investment in the Brazilian Transmission Lines.

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

Three Months Ended March 31, 2011	External Operating Revenues	Inter- segment Operating Revenues (In thousands)	Earnings on Common Stock
Electric	\$ 57,845	\$ —	\$ 8,524
Natural gas distribution	370,385	—	27,516
Pipeline and energy services	49,251	24,741	6,920
	477,481	24,741	42,960
Construction services	202,180	1,217	4,632
Natural gas and oil production	78,410	25,541	16,269
Construction materials and contracting	143,533	—	(21,402)
Other	201	2,288	347
	424,324	29,046	(154)
Intersegment eliminations	—	(53,787)	—
Total	\$ 901,805	\$ —	\$ 42,806

Three Months Ended March 31, 2010	External Operating Revenues	Inter- segment Operating Revenues (In thousands)	Earnings on Common Stock
Electric	\$ 49,696	\$ —	\$ 5,884
Natural gas distribution	349,026	—	23,344
Pipeline and energy services	61,523	27,086	8,791
	460,245	27,086	38,019
Construction services	153,066	23	127
Natural gas and oil production	71,659	35,927	22,211
Construction materials and contracting	149,807	—	(20,137)
Other	—	2,238	1,380
	374,532	38,188	3,581
Intersegment eliminations	—	(65,274)	—
Total	\$ 834,777	\$ —	\$ 41,600

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 March 31,	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	\$ 827	\$ 804	\$ 339	\$ 357
Interest cost	4,960	4,926	1,189	1,277
Expected return on assets	(5,700)	(5,692)	(1,218)	(1,392)
Amortization of prior service cost (credit)	43	38	(669)	(864)
Recognized net actuarial loss	1,543	972	311	388
Amortization of net transition obligation	—	—	531	532
Net periodic benefit cost, including amount capitalized	1,673	1,048	483	298
Less amount capitalized	248	276	(67)	47
Net periodic benefit cost	\$ 1,425	\$ 772	\$ 550	\$ 251

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. 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, will not be 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 months ended March 31, 2011 and 2010, was \$2.1 million.

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. The NDPSC has set a hearing on the settlement for May 2011.

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 February 23, 2011, Montana-Dakota and intervenors to the case jointly requested that the hearing set for February 28, 2011, be vacated and reset to a later date as the parties believed they would be able to negotiate a settlement agreement. The hearing was vacated on February 23, 2011. Settlement discussions are ongoing.

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 \$40.5 million and \$45.3 million for potential liabilities related to litigation and environmental matters as of March 31, 2011 and December 31, 2010, respectively, which includes \$26.6 million related to the natural gas gathering operations as well as amounts that may be reserved for other 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. 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 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, are estimated by the plaintiff as \$6.0 million to \$11.0 million. 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. 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 alleges 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. 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 alleges more than 360 violations of pipeline safety regulations and seeks relief including unspecified monetary penalties. Cascade filed its answer to the complaint admitting some and denying other of the alleged violations. Cascade recognized certain compliance issues and has been working with the WUTC to become fully compliant. 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 believes most of the violations have been or are in the process of being remedied. Cascade also intends to make significant additional technological and other investments over the next year to improve its compliance procedures and results. The WUTC will set a schedule for hearing the complaint. At this time, the Company cannot estimate the amount of likely civil penalty related to this matter.

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.

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. Cascade agreed to remove the pipe and perform the other time-critical actions pursuant to a work plan approved by the United States Coast Guard. The work satisfying the administrative order was completed in November 2010. It is expected that subsequent remedial action at the site will be conducted under the oversight of the EPA. 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.

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 March 31, 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 \$37.4 million and was reflected on the Consolidated Balance Sheet, at March 31, 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 March 31, 2011, the fixed maximum amounts guaranteed under these agreements aggregated \$181.7 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate \$105.8 million in 2011; \$67.6 million in 2012; \$1.2 million in 2013; \$200,000 in 2014; \$800,000 in 2018; \$300,000 in 2019; \$1.8 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 \$700,000 and was reflected on the Consolidated Balance Sheet at March 31, 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 March 31, 2011, the fixed maximum amounts guaranteed under these letters of credit, aggregated \$27.3 million. In 2011 and 2012, \$22.2 million and \$5.1 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at March 31, 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 March 31, 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 March 31, 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 March 31, 2011.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of

Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of March 31, 2011, approximately \$555 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. This segment continuously seeks opportunities to expand through strategic acquisitions.

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

Pipeline and Energy Services

Strategy Utilize the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new sources of natural gas for storage, gathering and transportation services; expansion of existing gathering, transmission and storage facilities; expansion of related energy services; and incremental expansion of pipeline capacity to allow customers access to more liquid and higher-priced markets.

Challenges Challenges for this segment include: energy price volatility; natural gas basis differentials; 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 March 31,	
	2011	2010
	(Dollars in millions, where applicable)	
Electric	\$8.5	\$5.9
Natural gas distribution	27.5	23.3
Construction services	4.6	.1
Pipeline and energy services	6.9	8.8
Natural gas and oil production	16.3	22.2
Construction materials and contracting	(21.4)	(20.1)
Other	(.1)	1.4
Earnings before discontinued operations	42.3	41.6
Income from discontinued operations, net of tax	.5	—
Earnings on common stock	\$42.8	\$41.6
Earnings per common share – basic:		
Earnings before discontinued operations	\$.22	\$.22
Discontinued operations, net of tax	.01	—
Earnings per common share – basic	\$.23	\$.22
Earnings per common share – diluted:		
Earnings before discontinued operations	\$.22	\$.22
Discontinued operations, net of tax	.01	—
Earnings per common share – diluted	\$.23	\$.22
Return on average common equity for the 12 months ended	9.1 %	10.5 %

Three Months Ended March 31, 2011 and 2010 Consolidated earnings for the quarter ended March 31, 2011, increased \$1.2 million from the comparable prior period largely due to:

- Higher construction workloads and margins, as well as higher equipment and electrical supply sales at the construction services business
- Increased retail sales volumes, partially offset by higher operation and maintenance expense at the natural gas distribution business

Partially offsetting these increases was:

- Lower average realized natural gas prices, higher depreciation, depletion and amortization expense, increased lease operating expenses and decreased natural gas production, partially

offset by higher average realized oil prices and increased oil production at the natural gas and oil production business

FINANCIAL AND OPERATING DATA

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

Electric

	Three Months Ended March 31,	
	2011	2010
(Dollars in millions, where applicable)		
Operating revenues	\$57.8	\$49.7
Operating expenses:		
Fuel and purchased power	16.9	16.9
Operation and maintenance	16.0	15.2
Depreciation, depletion and amortization	8.2	5.7
Taxes, other than income	2.5	2.7
	43.6	40.5
Operating income	14.2	9.2
Earnings	\$8.5	\$5.9
Retail sales (million kWh)	794.7	749.8
Sales for resale (million kWh)	6.7	29.8
Average cost of fuel and purchased power per kWh	\$0.020	\$0.021

Three Months Ended March 31, 2011 and 2010 Electric earnings increased \$2.6 million (45 percent) due to:

- Higher electric retail sales margins, primarily due to implementation of higher rates in Wyoming, as well as interim rates in North Dakota
 - An income tax benefit of \$700,000 related to favorable resolution of certain income tax matters
- Higher retail sales volumes of 6 percent, reflecting increased demand in all customer classes due to colder weather than last year

Partially offsetting these increases were:

- Increased depreciation, depletion and amortization expense of \$1.5 million (after tax), including the effects of higher property, plant and equipment balances
- Lower other income of \$1.1 million (after tax), primarily lower allowance for funds used during construction related to electric generation projects, which were placed in service in 2010

Natural Gas Distribution

	Three Months Ended March 31,			
	2011		2010	
	(Dollars in millions, where applicable)			
Operating revenues	\$370.4		\$349.0	
Operating expenses:				
Purchased natural gas sold	257.5		245.2	
Operation and maintenance	34.4		32.7	
Depreciation, depletion and amortization	11.1		10.6	
Taxes, other than income	17.7		16.5	
	320.7		305.0	
Operating income	49.7		44.0	
Earnings	\$27.5		\$23.3	
Volumes (MMdk):				
Sales	43.9		38.1	
Transportation	34.1		34.5	
Total throughput	78.0		72.6	
Degree days (% of normal)*				
Montana-Dakota	111	%	99	%
Cascade	103	%	86	%
Intermountain	105	%	95	%
Average cost of natural gas, including transportation, per dk	\$5.86		\$6.44	

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

Three Months Ended March 31, 2011 and 2010 Earnings at the natural gas distribution business increased \$4.2 million (18 percent) due to increased retail sales volumes, largely resulting from colder weather than last year. Partially offsetting this increase was higher operation and maintenance expense of \$1.4 million (after tax), primarily increased payroll and benefit-related costs.

Construction Services

	Three Months Ended March 31,	
	2011	2010
	(In millions)	
Operating revenues	\$203.4	\$153.1
Operating expenses:		
Operation and maintenance	184.9	141.8
Depreciation, depletion and amortization	2.9	3.3
Taxes, other than income	7.7	6.5
	195.5	151.6
Operating income	7.9	1.5
Earnings	\$4.6	\$1

Three Months Ended March 31, 2011 and 2010 Construction services earnings increased \$4.5 million primarily due to higher construction workload and margins, largely in the Western region. Also contributing to the earnings increase were higher equipment and electrical supply sales.

Pipeline and Energy Services

	Three Months Ended March 31, 2011 2010 (Dollars in millions)	
Operating revenues	\$74.0	\$88.6
Operating expenses:		
Purchased natural gas sold	34.1	47.5
Operation and maintenance	17.6	15.2
Depreciation, depletion and amortization	6.4	6.4
Taxes, other than income	3.6	3.0
	61.7	72.1
Operating income	12.3	16.5
Earnings	\$6.9	\$8.8
Transportation volumes (MMdk)	27.3	30.5
Gathering volumes (MMdk)	17.5	19.1
Customer natural gas storage balance (MMdk):		
Beginning of period	58.8	61.5
Net injection (withdrawal)	(25.9)	(18.0)
End of period	32.9	43.5

Three Months Ended March 31, 2011 and 2010 Pipeline and energy services earnings decreased \$1.9 million (21 percent) due to:

- Lower gathering volumes of \$700,000 (after tax)
- Decreased transportation volumes of \$700,000 (after tax), largely lower volumes transported to storage, as well as lower off-system transportation volumes
- Lower storage services revenue of \$400,000 (after tax)
- Lower energy-related services margins of \$400,000 (after tax)

Partially offsetting the earnings decrease was an income tax benefit of \$500,000 related to favorable resolution of certain income tax matters. The previous table also reflects higher operation and maintenance expense related to energy-related service projects.

Natural Gas and Oil Production

	Three Months Ended March 31, 2011 2010	
	(Dollars in millions, where applicable)	
Operating revenues:		
Natural gas	\$45.4	\$57.5
Oil	58.6	50.1
	104.0	107.6
Operating expenses:		
Operation and maintenance:		
Lease operating costs	18.0	15.8
Gathering and transportation	5.7	5.8
Other	8.3	8.7
Depreciation, depletion and amortization	34.2	29.7
Taxes, other than income:		
Production and property taxes	10.1	9.5
Other	.3	.3
	76.6	69.8
Operating income	27.4	37.8
Earnings	\$16.3	\$22.2
Production:		
Natural gas (MMcf)	11,758	12,243
Oil (MBbls)	802	761
Total Production (MMcfe)	16,570	16,808
Average realized prices (including hedges):		
Natural gas (per Mcf)	\$3.86	\$4.70
Oil (per Bbl)	\$72.98	\$65.79
Average realized prices (excluding hedges):		
Natural gas (per Mcf)	\$3.39	\$4.56
Oil (per Bbl)	\$79.24	\$66.40
Average depreciation, depletion and amortization rate, per equivalent Mcf	\$1.96	\$1.67
Production costs, including taxes, per equivalent Mcf:		
Lease operating costs	\$1.09	\$.94
Gathering and transportation	.34	.35
Production and property taxes	.61	.56
	\$2.04	\$1.85

Three Months Ended March 31, 2011 and 2010 Natural gas and oil production earnings decreased \$5.9 million (27 percent) due to:

- Lower average realized natural gas prices of 18 percent
- Higher depreciation, depletion and amortization expense of \$2.8 million (after tax), due to higher depletion rates
- Increased lease operating expenses of \$1.3 million (after tax), including higher well maintenance costs and costs associated with properties acquired in April 2010
- Decreased natural gas production of 4 percent, largely related to normal production declines at existing properties, partially offset by production from the Green River Basin properties, which were acquired in April 2010

Partially offsetting these decreases were:

- Higher average realized oil prices of 11 percent
- Increased oil production of 5 percent, largely related to drilling activity in the Bakken area, the previously mentioned Green River Basin properties, as well as from the South Texas properties, partially offset by normal production declines at certain existing properties

Construction Materials and Contracting

	Three Months Ended March 31,	
	2011	2010
	(Dollars in millions)	
Operating revenues	\$ 143.5	\$ 149.8
Operating expenses:		
Operation and maintenance	146.8	146.0
Depreciation, depletion and amortization	21.5	22.6
Taxes, other than income	7.7	7.2
	176.0	175.8
Operating loss	(32.5)	(26.0)
Loss	\$(21.4)	\$(20.1)
Sales (000's):		
Aggregates (tons)	2,827	2,963
Asphalt (tons)	165	154
Ready-mixed concrete (cubic yards)	397	476

Three Months Ended March 31, 2011 and 2010 Construction materials and contracting experienced a seasonal first quarter loss of \$21.4 million. This increased loss was the result of:

- Decreased construction margins of \$2.5 million (after tax), primarily due to weather-related delays
- Lower earnings of \$1.7 million (after tax) resulting from lower ready-mixed concrete margins and volumes, largely due to less available work, increased competition, as well as weather-related delays
 - Lower earnings of \$600,000 (after tax), resulting from lower aggregate volumes and margins

Partially offsetting the increased loss were:

- An income tax benefit of \$2.0 million related to favorable resolution of certain income tax matters
- Lower selling, general and administrative expense of \$1.4 million (after tax), largely payroll-related

Other and Intersegment Transactions

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

	Three Months Ended March 31, 2011 2010 (In millions)	
Other:		
Operating revenues	\$2.5	\$2.3
Operation and maintenance	2.9	1.9
Depreciation, depletion and amortization	.4	.4
Taxes, other than income	.1	.1
Intersegment transactions:		
Operating revenues	\$53.8	\$65.3
Purchased natural gas sold	46.9	59.0
Operation and maintenance	6.9	6.3

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:
 - o Second quarter – 20 percent
 - o Third quarter – 35 percent
 - o Fourth quarter – 25 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.
- The Company is analyzing potential projects for accommodating load growth and replacing purchased power contracts with company-owned generation. The Company is reviewing the construction of natural gas-fired combustion generation.
- The Company is pursuing opportunities associated with the potential development of high-voltage transmission lines and system enhancements targeted towards delivery of renewable energy from the wind rich regions that lie within its traditional electric service territory to major 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 2011. Its customers would not bear any of the costs associated with the project as costs will be recovered through an approved interconnect tariff. A major market party to the wind farm project has recently announced its intentions to withdraw from the project which may affect development 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 January 2016. 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.

Construction services

- Work backlog as of March 31, 2011, was approximately \$347 million, compared to \$400 million a year ago, and \$373 million at December 31, 2010. 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 approximately 30 percent for the trailing twelve months through March 31, 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. It continues to solicit further interest in the expansion.
- Final agreements have been executed to construct approximately 12 miles of high pressure transmission pipeline providing takeaway capacity for processed natural gas in northwestern North Dakota. The project is expected to be completed in the fourth quarter of 2011. The Company believes it is in a good position to provide similar services for other natural gas processing facilities in the area.
- The Company has three natural gas storage fields including the largest storage field in North America located near Baker, Montana. It continues to see 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 \$306 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 5 percent to 10 percent increase in oil production offset by a 4 percent to 8 percent decrease in natural gas production. 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 in late April 2011.
- Bakken – Mountrail County, North Dakota
 - o The Company owns approximately 16,000 net acres of leaseholds targeting the middle Bakken and Three Forks formations. The drilling of 12 operated and participation in various non-operated wells is planned for 2011 with approximately \$52 million of capital expenditures. Plans include drilling 12 wells annually for the two-year period 2012 through 2013.
 - oOver 50 future wells sites have been identified, 20 middle Bakken infill locations and the remainder Three Forks locations. Estimated gross ultimate recovery per well for the middle Bakken wells is 250,000 to 400,000 Bbls.

- Bakken – Stark County, North Dakota
 - o The Company holds approximately 50,000 net exploratory leasehold acres, targeting the Three Forks formation. It anticipates drilling 6 operated wells on this acreage and participating in various non-operated wells in Stark County in 2011 with capital of approximately \$37 million.
 - o Based on well results, the Company plans to drill 12 or more wells annually beginning in 2012.
 - o Based on 640-acre spacing, the acreage holds over 75 potential drill sites. Estimated gross ultimate recovery rates per well are 250,000 to 500,000 Bbls of oil equivalents. Based on initial well results and results by certain other producers, the play appears promising.
- Niobrara – southeastern Wyoming
 - o 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 2 exploratory wells in 2011.
 - o If successful, the Company plans to initiate a drilling program of approximately 12 wells annually starting in 2012.
 - o The Company also expects to participate in various non-operated wells in the Niobrara.
 - o 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 producers appear promising.
- Texas
 - o Based on low natural gas prices, the Company is targeting areas that have the potential for higher liquids content. It has approximately \$48 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 a test well 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 May through December as follows:

Index*	Price Per Mcf/Bbl
Natural gas:	
NYMEX	\$4.00 to \$4.50
Ventura	\$3.75 to \$4.25
CIG	\$3.50 to \$4.00
Oil:	
NYMEX	\$95.00 to \$100.00

* 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 nine months of 2011, the Company has hedged approximately 50 percent to 55 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 May 2, 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	4/11 - 12/11	1,017,500	\$8.00
Natural Gas	Swap	NYMEX	4/11 - 12/11	3,025,000	\$6.1027
Natural Gas	Swap	NYMEX	4/11 - 12/11	2,750,000	\$5.4975
Natural Gas	Swap	NYMEX	4/11 - 12/11	2,750,000	\$4.58
Natural Gas	Swap	NYMEX	4/11 - 12/11	2,750,000	\$4.70
Natural Gas	Swap	NYMEX	4/11 - 12/11	2,750,000	\$4.75
Natural Gas	Swap	NYMEX	4/11 - 10/11	2,140,000	\$4.775
Natural Gas	Swap	Ventura	5/11 - 10/11	1,840,000	\$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	4/11 - 12/11	412,500	\$80.00-\$94.00
Crude Oil	Collar	NYMEX	4/11 - 12/11	275,000	\$80.00-\$89.00
Crude Oil	Collar	NYMEX	4/11 - 12/11	137,500	\$77.00-\$86.45
Crude Oil	Collar	NYMEX	4/11 - 12/11	137,500	\$75.00-\$88.00
Crude Oil	Swap	NYMEX	4/11 - 12/11	275,000	\$81.35
Crude Oil	Swap	NYMEX	4/11 - 12/11	137,500	\$85.85
Crude Oil	Put Option	NYMEX	4/11 - 12/11	275,000	\$80.00*
Crude Oil	Call Option	NYMEX	4/11 - 12/11	275,000	\$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	4/11 - 12/11	3,025,000	\$0.395
Natural Gas	Basis Swap	Ventura	4/11 - 12/11	2,750,000	\$0.15
Natural Gas	Basis Swap	Ventura	4/11 - 12/11	1,375,000	\$0.15
Natural Gas	Basis Swap	Ventura	4/11 - 12/11	687,500	\$0.16
Natural Gas	Basis Swap	Ventura	4/11 - 12/11	2,750,000	\$0.16
Natural Gas	Basis Swap	Ventura	4/11 - 12/11	3,437,500	\$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 March 31, 2011, was approximately \$569 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 comparable at \$568 million. Total backlog at December 31, 2010, was \$420 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 recently 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 is also the primary cement provider and has the opportunity to supply a portion of the ready-mixed concrete and aggregate related to a light rail project in Hawaii. In addition, it has several significant multi-year projects it will place bids on in 2011. The Company 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 and margins to be comparable to 2010.
- Federal transportation stimulus of \$7.9 billion was directed to states where the Company operates. Of that amount, 69 percent was spent as of March 31, 2011, with the majority of the remaining \$2.4 billion to be spent during the remainder of 2011.
- The Company continues to pursue work related to energy projects, such as wind towers, transmission projects, geothermal and refineries. It is also pursuing opportunities for expansion of its existing business lines including initiatives aimed at capturing additional market share and expansion into new markets.
- The Company has a strong emphasis on operational efficiencies and cost reduction. Selling, general and administrative expenses are down approximately 40 percent for the trailing twelve months through March 31, 2011, compared to the annual expenses in 2006, the peak earnings year for this segment.
- As the country's 6th largest sand and gravel producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.
- Of the nine labor contracts that Knife River was negotiating, as reported in Items 1 and 2 – Business and Properties – General in the 2010 Annual Report, four have been ratified. The five 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, 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 March 31, 2011, the Company had cash and cash equivalents of \$136.0 million and available capacity of \$650.7 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 three months of 2011 increased \$35.3 million from the comparable period in 2010. The increase was largely due to higher deferred income taxes of \$26.3 million, largely the result of higher bonus depreciation.

Investing activities Cash flows used in investing activities in the first three months of 2011 decreased \$40.1 million from the comparable period in 2010. The decrease was primarily due to lower ongoing capital expenditures of \$41.2 million largely at the electric and natural gas distribution businesses.

Financing activities Cash flows used in financing activities in the first three months of 2011 increased \$93.2 million from the comparable period in 2010, largely resulting from the increased repayment of long-term debt and short-term borrowings of \$80.2 million and \$17.4 million, respectively.

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 three months of 2011 were \$59.5 million and are estimated to be approximately \$565 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 March 31, 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 March 31, 2011:

Company	Facility	Facility Limit (Dollars in millions)	Amount Outstanding	Letters of Credit	Expiration Date
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	\$125.0	\$— (b)	\$—	6/21/11
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	\$— (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 \$125 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of \$150 million). There were no amounts outstanding under the credit agreement.
- (b) Amount outstanding under commercial paper program.
- (c) 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.

In order to maintain the Company's and Centennial's respective commercial paper programs in the amounts indicated above, both the Company and Centennial must have revolving credit agreements in place at least equal to the amount of their commercial paper programs. While the amount of

commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. The Company's commercial paper borrowings are classified as short-term 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 March 31, 2011 and December 31, 2010, respectively.

Common stockholders' equity as a percent of total capitalization was 65 percent and 64 percent at March 31, 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. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement, which terminates on May 28, 2011. Proceeds from the sale of shares of common stock under the agreement have been and are expected to be used for corporate development purposes and other general corporate purposes. The Company had issued a total of approximately 3.2 million shares of stock under the Sales Agency Financing Agreement in 2009, resulting in total net proceeds of \$63.1 million. The Company did not issue any shares of stock during 2010 or the first quarter of 2011 under the Sales Agency Financing Agreement.

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

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. The Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings. Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the

capital markets. If Centennial were to experience a further downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

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

Off balance sheet arrangements

In connection with the sale of 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 March 31, 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	\$ 5.18	19,023	\$ 12,158
Natural gas swap agreements maturing in 2012	\$ 5.37	10,797	\$ 3,761
Natural gas basis swap agreements maturing in 2011	\$.21	14,025	\$ (924)
Natural gas basis swap agreements maturing in 2012	\$.41	3,477	\$ (116)
Oil swap agreements maturing in 2011	\$ 82.85	413	\$ (10,332)
Oil swap agreements maturing in 2012	\$ 100.05	366	\$ (2,264)
Cascade			
Natural gas swap agreements maturing in 2011	\$ 7.10	920	\$ (2,784)

	Weighted Average Floor/Ceiling Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Oil collar agreements maturing in 2011	\$78.86/\$90.64	963	\$ (17,855)
Oil collar agreements maturing in 2012	\$81.25/\$95.88	1,464	\$ (21,257)

	Deferred Premium	Weighted Average Floor (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Fidelity				
Oil put agreement maturing in 2011	\$4.00	\$ 80.00	275	\$ (845)
Oil call agreement maturing in 2011	\$4.00	\$ 103.00	275	\$ (1,725)

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 March 31, 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 the Brazilian Transmission Lines 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 March 31, 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 March 31, 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.

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. 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.

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

Between January 1, 2011 and March 31, 2011, the Company issued 7,515 shares of common stock, \$1.00 par value, as part of the consideration paid by the Company in the acquisition of a business acquired by the Company in a prior period. The common stock issued by the Company in this transaction was issued in a private transaction exempt from registration under the Securities Act of 1933, as amended, pursuant to Section 4(2) thereof, Rule 506 promulgated thereunder, or both. The classes of persons to whom these securities were sold were either accredited investors or other persons to whom such securities were permitted to be offered under the applicable exemption.

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 March 31, 2011, none of the Company's operating subsidiaries received citations or orders under the following sections of the Mine Safety Act: 104(d), 110(b)(2), 107(a) or 104(e). In addition, the Company did not have any mining-related fatalities during this period. The Company has 106 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, 4 were initiated during the three months ended March 31, 2011.

Information related to citations and assessments under the Mine Safety Act during the three months ended March 31, 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 March 31, 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 104(b) Citations Issued	Citations Contested	Proposed Assessments Levied	Outstanding as of March 31, 2011
Halawa Quarry	HI	2	—	—	\$ 6,904	\$28,579
Kona Sand Plant	HI	—	—	—	100	100
Portable 2	HI	—	—	—	300	300
Puunene Quarry	HI	—	—	—	200	760
Waikapu Quarry	HI	1	—	2	417	517
Waikapu Sand Pit	HI	—	—	—	100	100
Waimea Quarry	HI	—	—	—	—	138
Becker Portable #2	IA	—	—	—	—	576
T Olson Pit	MN	—	—	—	—	592
Billings Pit	MT	1	—	—	490	—
Dralle Pit	ND	—	—	—	—	300
Pioneer	ND	—	—	—	—	18,500
Wienmann Pit	ND	—	—	—	—	6,400
Angell Quarry	OR	—	—	—	—	100
Davis Slough	OR	1	—	—	—	1,872
Fisher Island	OR	—	—	—	1,125	200
Elk River	OR	—	—	—	—	1,355
Gresham S & G	OR	—	—	—	100	1,512
Lone Pine Portable	OR	—	—	—	—	100
Lone Pine Wash Plant	OR	—	—	—	100	—
Paetsch Pit	OR	—	1	2	200	112
Round Prairie	OR	1	—	—	—	—
Salem-Reed Pit	OR	1	—	—	—	9,273
Springfield Quarry	OR	—	—	—	—	190
Waterview	OR	—	—	—	400	802
Lampasas Quarry	TX	—	1	—	112	—
Sky High Pit	TX	1	—	—	424	424
Total		8	2	4	\$ 10,972	\$72,802

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 March 31, 2011.

Mine	State	Month Citation Issued	Contest Initiated By	Category of Violation	Proposed Assessments Levied (Dollars)*	Month Citation Closed**	Result of Contest**
Waikapu Quarry	HI	2/2011 ***	Operator	104	(a) \$ 100	—	—
Waikapu Quarry	HI	2/2011 ***	Operator	104	(a) 117	—	—
Becker Portable IA		7/2010	Operator	104	(a) 100	2/2011	Vacated
Becker Portable IA		7/2010	Operator	104	(a) 100	2/2011	Vacated
Becker Portable IA		7/2010	Operator	104	(a) 100	2/2011	Vacated
Little Falls	MN	10/2010	Operator	104	(a) 100	—	—
Little Falls	MN	11/2010	Operator	104	(a) 100	—	—
T Olson Pit	MN	10/2010	Operator	104	(a) 392	—	—
T Olson Pit	MN	10/2010	Operator	104	(a) 100	—	—
T Olson Pit	MN	10/2010	Operator	104	(a) 100	—	—
Rittenour Pit	MN	10/2010	Operator	104	(a) 100	—	—
Rittenour Pit	MN	10/2010	Operator	104	(a) 100	—	—
Rittenour Pit	MN	10/2010	Operator	104	(a) 362	—	—
Rockville 3	MN	11/2010	Operator	104	(d) —	—	—
Bender Pit	ND	8/2010	Operator	104	(a) 162	—	—
Bender Pit	ND	8/2010	Operator	104	(a) 100	—	—
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) —	—	—
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 March 31, 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: May 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) Long-Term Performance-Based Incentive Plan, as amended November 11, 2010 and February 17, 2011 and approved by stockholders on April 26, 2011
- +10(b) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 29, 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 March 31, 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 as blocks of text

+ Management contract, compensatory plan or arrangement.

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

