MDU RESOURCES GROUP INC
Form 10-Q
May 07, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

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

For The Quarterly Period Ended March 31, 2014

OR

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

For the Transition Period from _____________ to ______________

Commission file number 1-3480
MDU Resources Group, Inc.
(Exact name of registrant as specified in its charter)

Delaware (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 ý No o.

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

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

Large accelerated filer ý Accelerated filer o

Non-accelerated filer o Smaller reporting company o
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No ý.

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of April 30, 2014: 191,604,704 shares.

DEFINITIONS

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

Abbreviation or Acronym	
2013 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2013
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Bicent	Bicent Power LLC
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BLM	Bureau of Land Management
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
BOPD	Barrels of oil per day
Brazilian Transmission Lines	Company's investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and portions of the ownership interest in ECTE were sold in the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010)
Btu	British thermal unit
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CCU	Cane Creek Unit
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant being built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (2.5 percent ownership interest at March 31, 2014, 2.5, 2.5, 2.5 and 14.99 percent ownership interests were sold in the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010, respectively)
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
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
Fidelity Oil Co.	A direct wholly owned subsidiary of Fidelity
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital

JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
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
kWh	Kilowatt-hour
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE
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
MISO	Midcontinent Independent System Operator, Inc.
MMBbls	Millions of barrels
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million decatherms
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MW	Megawatt
NDPSC	North Dakota Public Service Commission
New York Supreme Court	Supreme Court of the State of New York, County of New York
NGL	Natural gas liquids
NSPS	New Source Performance Standards
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility 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
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
SEC	U.S. Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
SourceGas	SourceGas Distribution LLC
VIE	Variable interest entity
WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings (previously Bitter Creek Pipelines, LLC, name changed effective July 1, 2012)
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings (previously Williston Basin Interstate Pipeline Company, name changed effective July 1,

	2012)
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
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 exploration and 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 16.

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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,	
	2014	2013
	(In thousands, except per share amounts)	
Operating revenues:		
Electric, natural gas distribution and pipeline and energy services	$491,541	$424,124
Exploration and production, construction materials and contracting, construction services and other	551,312	507,480
Total operating revenues	1,042,853	931,604
Operating expenses:		
Fuel and purchased power	26,544	21,608
Purchased natural gas sold	244,892	199,187
Operation and maintenance:		
Electric, natural gas distribution and pipeline and energy services	67,284	66,101
Exploration and production, construction materials and contracting, construction services and other	445,951	394,019
Depreciation, depletion and amortization	99,557	93,561
Taxes, other than income	55,721	52,597
Total operating expenses	939,949	827,073
Operating income	102,904	104,531
Earnings (loss) from equity method investments	51	(311)
Other income	2,132	1,242
Interest expense	20,971	20,874
Income before income taxes	84,116	84,588
Income taxes	27,932	27,996
Income from continuing operations	56,184	56,592
Loss from discontinued operations, net of tax (Note 9)	(45)	(77)
Net income	56,139	56,515
Net loss attributable to noncontrolling interest	(523)	—
Dividends declared on preferred stocks	171	171
Earnings on common stock	$56,491	$56,344
Earnings per common share - basic:		
Earnings before discontinued operations	$.30	$.30
Discontinued operations, net of tax	—	—
Earnings per common share - basic	$.30	$.30
Earnings per common share - diluted:		
Earnings before discontinued operations	$.30	$.30
Discontinued operations, net of tax	—	—
Earnings per common share - diluted	$.30	$.30

Dividends declared per common share	$.1775	$.1725
Weighted average common shares outstanding - basic	189,820	188,831
Weighted average common shares outstanding - diluted	190,432	189,222

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

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

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Net income	$56,139	$56,515
Other comprehensive income (loss):		
Net unrealized gain (loss) on derivative instruments qualifying as hedges:		
Net unrealized loss on derivative instruments arising during the period, net of tax of $0 and $(3,168) for the three months ended in 2014 and 2013, respectively	—	(5,849)
Reclassification adjustment for (gain) loss on derivative instruments included in net income, net of tax of $204 and $(1,626) for the three months ended in 2014 and 2013, respectively	344	(2,772)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	344	(8,621)
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $168 and $319 for the three months ended in 2014 and 2013, respectively	275	648
Foreign currency translation adjustment recognized during the period, net of tax of $28 and $37 for the three months ended in 2014 and 2013, respectively	46	88
Net unrealized gain (loss) on available-for-sale investments:		
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(19) and $(24) for the three months ended in 2014 and 2013, respectively	(36)	(44)
Reclassification adjustment for loss on available-for-sale investments included in net income, net of tax of $20 and $19 for the three months ended in 2014 and 2013, respectively	38	35
Net unrealized gain (loss) on available-for-sale investments	2	(9)
Other comprehensive income (loss)	667	(7,894)
Comprehensive income	56,806	48,621
Comprehensive loss attributable to noncontrolling interest	(523)	—
Comprehensive income attributable to common stockholders	$57,329	$48,621

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

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

(In thousands, except shares and per share amounts)	March 31, 2014	March 31, 2013	December 31, 2013
ASSETS			
Current assets:			
Cash and cash equivalents	$83,700	$74,149	$45,225
Receivables, net	690,761	635,564	713,067
Inventories	301,332	334,872	282,391
Deferred income taxes	29,427	29,885	25,048
Commodity derivative instruments	81	5,936	1,447
Prepayments and other current assets	99,229	68,828	49,510
Total current assets	1,204,530	1,149,234	1,116,688
Investments	113,763	106,846	112,939
Property, plant and equipment	9,150,269	8,303,065	8,803,866
Less accumulated depreciation, depletion and amortization	3,954,442	3,678,535	3,872,487
Net property, plant and equipment	5,195,827	4,624,530	4,931,379
Deferred charges and other assets:			
Goodwill	636,039	636,039	636,039
Other intangible assets, net	12,296	16,318	13,099
Other	246,394	295,215	251,188
Total deferred charges and other assets	894,729	947,572	900,326
Total assets	$7,408,849	$6,828,182	$7,061,332
LIABILITIES AND EQUITY			
Current liabilities:			
Short-term borrowings	$—	$37,500	$11,500
Long-term debt due within one year	12,227	171,094	12,277
Accounts payable	399,935	375,942	404,961
Taxes payable	61,847	55,748	74,175
Dividends payable	33,980	32,744	33,737
Accrued compensation	40,016	31,382	69,661
Commodity derivative instruments	12,186	7,379	7,483
Other accrued liabilities	185,287	205,394	171,106
Total current liabilities	745,478	917,183	784,900
Long-term debt	2,093,605	1,618,569	1,842,286
Deferred credits and other liabilities:			
Deferred income taxes	899,420	802,805	859,306
Other liabilities	720,542	814,643	718,938
Total deferred credits and other liabilities	1,619,962	1,617,448	1,578,244
Commitments and contingencies			
Equity:			
Preferred stocks	15,000	15,000	15,000
Common stockholders' equity:			
Common stock			
Authorized - 500,000,000 shares, $1.00 par value			
Shares issued - 191,838,720 at March 31, 2014,	191,839	189,369	189,869

189,369,450 at March 31, 2013 and 189,868,780 at December 31, 2013			
Other paid-in capital	1,110,221	1,038,970	1,056,996
Retained earnings	1,625,692	1,480,784	1,603,130
Accumulated other comprehensive loss	(37,538)	(56,615)	(38,205)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,886,588	2,648,882	2,808,164
Total stockholders' equity	2,901,588	2,663,882	2,823,164
Noncontrolling interest	48,216	11,100	32,738
Total equity	2,949,804	2,674,982	2,855,902
Total liabilities and equity	$7,408,849	$6,828,182	$7,061,332

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, 2014	2013
	(In thousands)	
Operating activities:		
Net income	$56,139	$56,515
Loss from discontinued operations, net of tax	(45)	(77)
Income from continuing operations	56,184	56,592
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	99,557	93,561
Earnings (loss), net of distributions, from equity method investments	(51)	1,277
Deferred income taxes	35,965	44,663
Unrealized loss on commodity derivatives	6,712	5,832
Changes in current assets and liabilities, net of acquisitions:		
Receivables	25,611	32,206
Inventories	(19,809)	(19,126)
Other current assets	(22,324)	(25,855)
Accounts payable	(11,525)	(35,091)
Other current liabilities	(28,355)	(7,338)
Other noncurrent changes	(4,936)	(10,150)
Net cash provided by continuing operations	137,029	136,571
Net cash provided by discontinued operations	8	303
Net cash provided by operating activities	137,037	136,874
Investing activities:		
Capital expenditures	(179,646)	(188,475)
Acquisitions, net of cash acquired	(206,304)	—
Net proceeds from sale or disposition of property and other	5,179	18,176
Investments	458	(514)
Net cash used in continuing operations	(380,313)	(170,813)
Net cash provided by discontinued operations	—	—
Net cash used in investing activities	(380,313)	(170,813)
Financing activities:		
Issuance of short-term borrowings	—	9,300
Repayment of short-term borrowings	(11,500)	—
Issuance of long-term debt	309,501	112,015
Repayment of long-term debt	(58,232)	(67,123)
Proceeds from issuance of common stock	54,843	—
Dividends paid	(33,737)	(171)
Excess tax benefit on stock-based compensation	4,833	—
Contribution from noncontrolling interest	16,000	5,000
Net cash provided by continuing operations	281,708	59,021
Net cash provided by discontinued operations	—	—
Net cash provided by financing activities	281,708	59,021

Effect of exchange rate changes on cash and cash equivalents	43	25
Increase in cash and cash equivalents	38,475	25,107
Cash and cash equivalents -- beginning of year	45,225	49,042
Cash and cash equivalents -- end of period	$83,700	$74,149

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

March 31, 2014 and 2013
(Unaudited)

Note 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 2013 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 2013 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, 2014, up to the date of issuance of these consolidated interim financial statements.

Note 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.

Note 3 - Accounts receivable and allowance for doubtful accounts
Accounts receivable consist 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 $22.6 million, $39.6 million and $36.4 million at March 31, 2014 and 2013, and December 31, 2013, 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 at March 31, 2014 and 2013, and December 31, 2013, was $10.9 million, $10.8 million and $10.1 million, respectively.

Note 4 - Inventories and natural gas in storage
Inventories, other than natural gas in storage for the Company's regulated operations, are 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 is included in inventories. Inventories consisted of:

	March 31, 2014	March 31, 2013	December 31, 2013
	(In thousands)		
Aggregates held for resale	$104,106	$98,120	$101,568
Asphalt oil	66,292	94,332	38,099
Materials and supplies	68,809	75,868	69,808
Merchandise for resale	22,463	24,342	21,720
Natural gas in storage (current)	6,129	12,811	16,417

Other	33,533	29,399	34,779
Total	$301,332	$334,872	$282,391

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, is included in other assets and was $47.4 million, $49.6 million, and $48.3 million at March 31, 2014 and 2013, and December 31, 2013, respectively.

Note 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 performance share awards. Common stock outstanding includes issued shares less shares held in treasury. Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculations was as follows:

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Weighted average common shares outstanding - basic	189,820	188,831
Effect of dilutive performance share awards	612	391
Weighted average common shares outstanding - diluted	190,432	189,222
Shares excluded from the calculation of diluted earnings per share	—	—

Note 6 - Cash flow information

Cash expenditures for interest and income taxes were as follows:

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Interest, net of amount capitalized	$20,850	$21,857
Income taxes paid (refunded), net	$9,435	$(7,246)

Noncash investing transactions were as follows:

	March 31,	
	2014	2013
	(In thousands)	
Property, plant and equipment additions in accounts payable	$65,736	$92,236

Note 7 - Comprehensive income (loss)

The after-tax changes in the components of accumulated other comprehensive loss at March 31, 2014, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at December 31, 2013	$(3,765)	$(33,807)	$(667)	$ 34	$(38,205)
Other comprehensive income (loss) before reclassifications	—	—	46	(36)	10
Amounts reclassified from accumulated other comprehensive loss	344	275	—	38	657

Net current-period other comprehensive income	344	275	46	2	667
Balance at March 31, 2014	$(3,421)	$(33,532)	$(621)	$ 36	$(37,538)

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The after-tax changes in the components of accumulated other comprehensive loss at March 31, 2013, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at December 31, 2012	$6,018	$(54,347)	$(511)	$ 119	$(48,721)
Other comprehensive income (loss) before reclassifications	(5,849)	—	88	(44)	(5,805)
Amounts reclassified from accumulated other comprehensive loss	(2,772)	648	—	35	(2,089)
Net current-period other comprehensive income (loss)	(8,621)	648	88	(9)	(7,894)
Balance at March 31, 2013	$(2,603)	$(53,699)	$(423)	$ 110	$(56,615)

Reclassifications out of accumulated other comprehensive loss were as follows:

	Three Months Ended March 31, 2014	March 31, 2013	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for gain (loss) on derivative instruments included in net income:			
Commodity derivative instruments	$(388)	$4,513	Operating revenues
Interest rate derivative instruments	(160)	(115)	Interest expense
	(548)	4,398	
	204	(1,626)	Income taxes
	(344)	2,772	
Amortization of postretirement liability losses included in net periodic benefit cost	(443)	(967)	(a)
	168	319	Income taxes
	(275)	(648)	
Reclassification adjustment for loss on available-for-sale investments included in net income	(58)	(54)	Other income
	20	19	Income taxes
	(38)	(35)	
Total reclassifications	$(657)	$2,089	

(a) Included in net periodic benefit cost (credit). For more information, see Note 17.

Note 8 - Acquisition

On February 10, 2014, the Company entered into agreements to purchase working interests and leasehold positions in oil and natural gas production assets in the southern Powder River Basin of Wyoming. The effective date of the acquisition was October 1, 2013, and the closing occurred on March 6, 2014. The purchase price was $206.3 million, including purchase price adjustments.

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

Note 9 - Discontinued operations
In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources had agreed to indemnify Bicent 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 incurs legal expenses, which are reflected as discontinued operations in the consolidated financial statements and accompanying notes, and has accrued liabilities related to this matter. Discontinued operations are included in the Other category. For more information, see Note 19.

Note 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. At March 31, 2014, the Company had no significant equity method investments.

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 2009, multiple sales agreements were signed for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale of its entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE. The Company's remaining interest in ECTE is being sold over a four-year period. In August 2013 and 2012, and November 2011, the Company completed the sale of one-fourth of the remaining interest in each year. The Company recognized an immaterial gain in 2013. The Company's remaining ownership interest in ECTE is being accounted for under the cost method.

At March 31, 2013, the equity method investments had total assets of $142.9 million and long-term debt of $63.9 million. The Company's investment in its equity method investments was approximately $5.7 million, including undistributed earnings of $2.2 million, at March 31, 2013.

Note 11 - Goodwill and other intangible assets
The changes in the carrying amount of goodwill were as follows:

Three Months Ended March 31, 2014	Balance as of January 1, 2014*	Goodwill Acquired During the Year	Balance as of March 31, 2014*
	(In thousands)		
Natural gas distribution	$345,736	$—	$345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	104,276	—	104,276
Total	$636,039	$—	$636,039

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

Three Months Ended March 31, 2013	Balance as of January 1, 2013*	Goodwill Acquired During the Year	Balance as of March 31, 2013*
	(In thousands)		
Natural gas distribution	$345,736	$—	$345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	104,276	—	104,276
Total	$636,039	$—	$636,039

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

Year Ended December 31, 2013	Balance as of January 1, 2013*	Goodwill Acquired During the Year	Balance as of December 31, 2013*
	(In thousands)		
Natural gas distribution	$345,736	$—	$345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	104,276	—	104,276
Total	$636,039	$—	$636,039

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

Other amortizable intangible assets were as follows:

	March 31, 2014	March 31, 2013	December 31, 2013
	(In thousands)		
Customer relationships	$21,310	$21,310	$21,310
Accumulated amortization	(14,230)	(12,211)	(13,726)
	7,080	9,099	7,584
Noncompete agreements	5,580	7,236	6,186
Accumulated amortization	(4,335)	(5,439)	(4,840)
	1,245	1,797	1,346
Other	10,920	10,979	10,995
Accumulated amortization	(6,949)	(5,557)	(6,826)
	3,971	5,422	4,169
Total	$12,296	$16,318	$13,099

Amortization expense for amortizable intangible assets for the three months ended March 31, 2014 and 2013, was $800,000 and $800,000, respectively. Estimated amortization expense for amortizable intangible assets is $3.2 million in 2014, $2.5 million in 2015, $2.2 million in 2016, $2.0 million in 2017, $1.0 million in 2018 and $2.2 million thereafter.

Note 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, 2014, the Company had no outstanding foreign currency or interest rate hedges.

The fair value of 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 a liability.

Fidelity

At March 31, 2014 and 2013, and December 31, 2013, Fidelity held oil swap and collar agreements with total forward notional volumes of 2.7 million, 2.8 million and 2.9 million Bbl, respectively, and natural gas swap agreements with total forward notional volumes of 14.7 million, 25.9 million and 18.3 million MMBtu, respectively. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas on its forecasted sales of oil and natural gas production.

Effective April 1, 2013, Fidelity elected to de-designate all commodity derivative contracts previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively for all of its commodity derivative instruments. When the criteria for hedge accounting is not met or when hedge accounting is not elected, realized gains and losses and unrealized gains and losses are both recorded in operating revenues on the Consolidated Statements of Income. As a result of discontinuing hedge accounting on commodity derivative instruments, gains and losses on the oil and natural gas derivative instruments remain in accumulated other comprehensive income (loss) as of the de-designation date and are reclassified into earnings in future periods as the underlying hedged transactions affect earnings. At April 1, 2013, accumulated other comprehensive income (loss) included $1.8 million of unrealized gains, representing the mark-to-market value of the Company's commodity derivative instruments that qualified as cash flow hedges as of the balance sheet date. The Company expects to reclassify into earnings from accumulated other comprehensive income (loss) the remaining value related to de-designating commodity derivative instruments over the next 9 months.

Prior to April 1, 2013, changes in the fair value attributable to the effective portion of the hedging instruments, net of tax, were recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges were not effective or did not qualify for hedge accounting, the ineffective portion of the changes in fair market value was recorded directly in earnings. Gains and losses on the oil and natural gas derivative instruments were reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the oil and natural gas quantities were settled.

Centennial
As of March 31, 2014 and December 31, 2013, Centennial had no outstanding interest rate swap agreements. At March 31, 2013, Centennial held interest rate swap agreements with total notional amounts of $40.0 million which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt.

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). To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings.

Fidelity and Centennial
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, and there were no such reclassifications.

The gains and losses on derivative instruments were as follows:

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Commodity derivatives designated as cash flow hedges:		
Amount of loss recognized in accumulated other comprehensive loss (effective portion), net of tax	$ —	$ (6,154)
Amount of (gain) loss reclassified from accumulated other comprehensive loss into operating revenues (effective portion), net of tax	244	(2,843)
Amount of loss recognized in operating revenues (ineffective portion), before tax	—	(1,422)
Interest rate derivatives designated as cash flow hedges:		
Amount of gain recognized in accumulated other comprehensive loss (effective portion), net of tax	—	305
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	100	71
Amount of loss recognized in interest expense (ineffective portion), before tax	—	(159)
Commodity derivatives not designated as hedging instruments:		
Amount of loss recognized in operating revenues, before tax	(6,712)	(4,410)

Over the next 12 months net losses of approximately $449,000 (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of the derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that are in a liability position at March 31, 2014 and 2013, and December 31, 2013, were $12.2 million, $12.4 million and $7.5 million, respectively. 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, 2014 and 2013, and December 31, 2013, were $12.2 million, $12.4 million and $7.5 million, respectively.

The location and fair value of the gross amount 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, 2014	Fair Value at March 31, 2013	Fair Value at December 31, 2013
		(In thousands)		
Designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$—	$1,623	$—
		—	1,623	—
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	81	4,313	1,447
	Other assets - noncurrent	249	243	503
		330	4,556	1,950
Total asset derivatives		$330	$6,179	$1,950

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at March 31, 2014	Fair Value at March 31, 2013	Fair Value at December 31, 2013
		(In thousands)		
Designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$—	$5,994	$—
	Other liabilities - noncurrent	—	534	—
Interest rate derivatives	Other accrued liabilities	—	4,458	—
		—	10,986	—
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	12,186	1,385	7,483
	Other liabilities - noncurrent	—	74	—
		12,186	1,459	7,483
Total liability derivatives		$12,186	$12,445	$7,483

All of the Company's commodity and interest rate derivative instruments at March 31, 2014 and 2013, and December 31, 2013, were subject to legally enforceable master netting agreements. However, the Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. The gross derivative assets and liabilities (excluding settlement receivables and payables that may be subject to the same master netting agreements) presented on the Consolidated Balance Sheets and the amount eligible for offset under the master netting agreements is presented in the following table:

March 31, 2014	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$330	$(330)	$—
Total assets	$330	$(330)	$—
Liabilities:			
Commodity derivatives	$12,186	$(330)	$11,856

Total liabilities	$ 12,186	$ (330	) $ 11,856

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March 31, 2013	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$6,179	$(3,578)	$2,601
Total assets	$6,179	$(3,578)	$2,601
Liabilities:			
Commodity derivatives	$7,987	$(3,578)	$4,409
Interest rate derivatives	4,458	—	4,458
Total liabilities	$12,445	$(3,578)	$8,867

December 31, 2013	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$1,950	$(1,950)	$—
Total assets	$1,950	$(1,950)	$—
Liabilities:			
Commodity derivatives	$7,483	$(1,950)	$5,533
Total liabilities	$7,483	$(1,950)	$5,533

Note 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, which consist of an insurance contract, 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 $63.3 million, $53.3 million and $62.4 million, as of March 31, 2014 and 2013, and December 31, 2013, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments were $900,000 and $4.4 million for the three months ended March 31, 2014 and 2013, 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, which records gains and losses in income, for its available-for-sale securities, which include 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. Unrealized gains or losses are recorded in accumulated other comprehensive income (loss). Details of available-for-sale securities were as follows:

March 31, 2014	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$7,943	$63	$(17)	$7,989
U.S. Treasury securities	2,069	9	—	2,078
Total	$10,012	$72	$(17)	$10,067

March 31, 2013	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$ 8,749	$ 133	$ (3)	$ 8,879
U.S. Treasury securities	1,301	39	—	1,340
Total	$ 10,050	$ 172	$ (3)	$ 10,219

December 31, 2013	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$ 8,151	$ 69	$ (27)	$ 8,193
U.S. Treasury securities	1,906	15	(4)	1,917
Total	$ 10,057	$ 84	$ (31)	$ 10,110

The fair value of the Company's money market funds approximates cost.

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 estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach.

The Company's 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 mortgage-backed securities and U.S. Treasury securities are based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources.

The estimated fair value of the Company's Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

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 Company's and the counterparties' nonperformance risk is also evaluated.

The estimated fair value of the Company's Level 2 interest rate derivative instruments is measured using quoted market prices or pricing models using prevailing market interest rates as of the measurement date. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' 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, 2014 and 2013, there were no transfers between Levels 1 and 2.

The Company's assets and liabilities measured at fair value on a recurring basis were as follows:

	Fair Value Measurements at March 31, 2014, 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, 2014
	(In thousands)			
Assets:				
Money market funds	$—	$20,267	$—	$20,267
Insurance contract*	—	63,269	—	63,269
Available-for-sale securities:				
Mortgage-backed securities	—	7,989	—	7,989
U.S. Treasury securities	—	2,078	—	2,078
Commodity derivative instruments	—	330	—	330
Total assets measured at fair value	$—	$93,933	$—	$93,933
Liabilities:				
Commodity derivative instruments	$—	$12,186	$—	$12,186
Total liabilities measured at fair value	$—	$12,186	$—	$12,186

* The insurance contract invests approximately 29 percent in common stock of mid-cap companies, 27 percent in common stock of small-cap companies, 28 percent in common stock of large-cap companies and 16 percent in fixed-income investments.

	Fair Value Measurements at March 31, 2013, 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, 2013
	(In thousands)			
Assets:				
Money market funds	$—	$31,281	$—	$31,281
Insurance contract*	—	53,334	—	53,334
Available-for-sale securities:				
Mortgage-backed securities	—	8,879	—	8,879
U.S. Treasury securities	—	1,340	—	1,340
Commodity derivative instruments	—	6,179	—	6,179
Total assets measured at fair value	$—	$101,013	$—	$101,013
Liabilities:				
Commodity derivative instruments	$—	$7,987	$—	$7,987
Interest rate derivative instruments	—	4,458	—	4,458
Total liabilities measured at fair value	$—	$12,445	$—	$12,445

* The insurance contract invests approximately 29 percent in common stock of mid-cap companies, 28 percent in common stock of small-cap companies, 28 percent in common stock of large-cap companies and 15 percent in fixed-income investments.

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	Fair Value Measurements at December 31, 2013, 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, 2013
	(In thousands)			
Assets:				
Money market funds	$—	$19,227	$—	$19,227
Insurance contract*	—	62,370	—	62,370
Available-for-sale securities:				
Mortgage-backed securities	—	8,193	—	8,193
U.S. Treasury securities	—	1,917	—	1,917
Commodity derivative instruments	—	1,950	—	1,950
Total assets measured at fair value	$—	$93,657	$—	$93,657
Liabilities:				
Commodity derivative instruments	$—	$7,483	$—	$7,483
Total liabilities measured at fair value	$—	$7,483	$—	$7,483

* The insurance contract invests approximately 29 percent in common stock of mid-cap companies, 28 percent in common stock of small-cap companies, 28 percent in common stock of large-cap companies and 15 percent in fixed-income investments.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The fair value was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt was as follows:

	Carrying Amount	Fair Value
	(In thousands)	
Long-term debt at March 31, 2014	$2,105,832	$2,186,839
Long-term debt at March 31, 2013	$1,789,663	$1,925,859
Long-term debt at December 31, 2013	$1,854,563	$1,912,590

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

Note 14 - Long-term debt

Centennial entered into a two year $125.0 million term loan agreement with a variable interest rate on March 31, 2014. In addition, borrowings outstanding that were classified as long-term debt under the Company’s and Centennial’s commercial paper programs totaled $283.5 million at March 31, 2014, compared to $153.9 million at December 31, 2013, respectively.

Note 15 - Equity

A summary of the changes in equity was as follows:

Three Months Ended March 31, 2014	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
	(In thousands)		
Balance at December 31, 2013	$2,823,164	$32,738	$2,855,902
Net income (loss)	56,662	(523)	56,139
Other comprehensive income	667	—	667
Dividends declared on preferred stocks	(171)	—	(171)
Dividends declared on common stock	(33,809)	—	(33,809)
Stock-based compensation	1,336	—	1,336
Issuance of common stock upon vesting of performance shares, net of shares used for tax withholdings	(5,564)	—	(5,564)
Net tax benefit on stock-based compensation	4,729	—	4,729
Issuance of common stock	54,574	—	54,574
Contribution from noncontrolling interest	—	16,001	16,001
Balance at March 31, 2014	$2,901,588	$48,216	$2,949,804

Three Months Ended March 31, 2013	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
	(In thousands)		
Balance at December 31, 2012	$2,648,248	$—	$2,648,248
Net income	56,515	—	56,515
Other comprehensive loss	(7,894)	—	(7,894)
Dividends declared on preferred stocks	(171)	—	(171)
Dividends declared on common stock	(32,573)	—	(32,573)
Stock-based compensation	1,176	—	1,176
Net tax deficit on stock-based compensation	(1,419)	—	(1,419)
Contribution from noncontrolling interest	—	11,100	11,100
Balance at March 31, 2013	$2,663,882	$11,100	$2,674,982

Note 16 - Business segment data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these operating segments is defined based on the reporting and review process used by the Company's chief executive officer. The vast majority of the Company's operations are located within the United States. The Company also has an investment in a foreign country, which consists of Centennial Resources' investment in ECTE.

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

The pipeline and energy services segment provides natural gas transportation, underground storage, processing and gathering services, as well as oil gathering, through regulated and nonregulated pipeline systems and processing facilities primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment is constructing Dakota Prairie Refinery in conjunction with Calumet to refine crude oil and also provides cathodic protection and other energy-related services.

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

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 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 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, automobile liability and pollution liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes Centennial Resources' investment in ECTE.

The information below follows the same accounting policies as described in Note 1 of the Company's Notes to Consolidated Financial Statements in the 2013 Annual Report. Information on the Company's businesses was as follows:

Three Months Ended March 31, 2014	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$73,647	$—	$11,033
Natural gas distribution	374,233	—	27,263
Pipeline and energy services	43,661	18,276	4,349
	491,541	18,276	42,645
Exploration and production	116,669	20,867	20,939
Construction materials and contracting	164,423	4,017	(23,574)
Construction services	269,892	3,738	16,568
Other	328	1,724	264
	551,312	30,346	14,197
Intersegment eliminations	—	(48,622)	(351)
Total	$1,042,853	$—	$56,491

Three Months Ended March 31, 2013	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$64,654	$—	$9,825
Natural gas distribution	331,754	—	32,518
Pipeline and energy services	27,716	18,718	2,330
	424,124	18,718	44,673
Exploration and production	115,363	9,812	20,284
Construction materials and contracting	161,977	4,294	(20,582)
Construction services	229,806	1,574	11,664
Other	334	1,818	305
	507,480	17,498	11,671
Intersegment eliminations	—	(36,216)	—
Total	$931,604	$—	$56,344

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

Note 17 - Employee benefit plans
The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans were as follows:

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended March 31,	2014	2013	2014	2013
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$33	$40	$379	$504
Interest cost	4,440	4,018	858	940
Expected return on assets	(5,125)	(5,083)	(1,067)	(1,107)
Amortization of prior service cost (credit)	18	18	(348)	(364)
Amortization of net actuarial loss	1,313	1,864	318	671
Net periodic benefit cost, including amount capitalized	679	857	140	644
Less amount capitalized	95	110	29	29
Net periodic benefit cost	$584	$747	$111	$615

In addition to the qualified plan defined pension benefits reflected in the table, the Company has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide 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, 2014 and 2013, was $1.7 million and $1.9 million, respectively.

Note 18 - Regulatory matters and revenues subject to refund
On April 8, 2014, Montana-Dakota submitted a request to the NDPSC to update the environmental cost recovery rider to reflect actual costs incurred through February 2014 and projected costs through June 2015 related to the recovery of Montana-Dakota's share of the costs resulting from the environmental retrofit required to be installed at the Big Stone Station. If approved, the rates would be effective with service rendered on and after July 1, 2014.

On September 18, 2013, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase. Montana-Dakota requested a total increase of $6.8 million annually or approximately 6.4 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, an operations building, automated meter reading and a new customer billing system. An interim increase of $4.3 million annually or approximately 4.0 percent went into effect for service rendered on or after November 17, 2013. On December 30, 2013, the NDPSC approved a settlement agreement for an increase in the same amount as the interim increase. A hearing on the rate design portion of the case was held February 5, 2014. The NDPSC voted to approve an order approving the allocation of the revenue increase to each rate class and the rate design on April 9, 2014. Final rates were implemented May 1, 2014.

On February 27, 2014, Montana-Dakota filed an application with the NDPSC for approval of an electric generation resource recovery rider for recovery of Montana-Dakota's investment in the 88-megawatt simple-cycle natural gas turbine and associated facilities currently under construction near Mandan, ND. Montana-Dakota requested recovery of $7.4 million annually or approximately 4.6 percent above current rates. Advance determination of prudence and a certificate of public convenience and necessity were received from the NDPSC on April 11, 2012. On March 12, 2014, the NDPSC suspended the filing pending further review. The NDPSC has scheduled a hearing for this matter on May 28, 2014.

On October 31, 2013, WBI Energy Transmission filed a general natural gas rate change application with the FERC for an increase of $28.9 million annually to cover increased investments of $312 million, increased operating costs, and the effect of lower storage and off system volumes. On April 30, 2014, WBI Energy Transmission reached a settlement in principle with FERC Trial Staff and all active parties to resolve the rate case. WBI Energy Transmission intends to file the settlement rates to take effect on an interim basis, effective May 1, 2014, pending final approval of the settlement. The settlement, if approved, will result in final rates which are lower than the rates which were originally requested in the rate case application.

Note 19 - Contingencies
The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of \$31.4 million, \$33.3 million and \$29.5 million for contingencies, including litigation, production taxes, royalty claims and environmental matters, as of March 31, 2014 and 2013, and December 31, 2013, respectively, which include amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation
Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee 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 seeking compensatory damages of \$149.7 million. An arbitration award was issued January 13, 2012, awarding LPP \$22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award was recorded in discontinued operations on the Consolidated Statement of Income in the fourth quarter of 2011. CEM filed a petition with the New York Supreme Court to vacate the arbitration award in favor of LPP. On October 19, 2012, Centennial moved to intervene in the New York Supreme Court action to vacate the arbitration award and also filed a complaint with the New York Supreme Court seeking a declaration that LPP is not entitled to indemnification from Centennial under the guaranty for the arbitration award. The New York Supreme Court granted CEM's petition to vacate the arbitration award on November 20, 2012, and entered an order and judgment to that effect on June 5, 2013. LPP appealed the order and judgment and on February 20, 2014, the New York Supreme Court Appellate Division ruled the arbitration award was properly vacated. LPP filed a motion with the New York Court of Appeals for leave to appeal the decision of the New York Supreme Court Appellate Division. The motion remains pending. Due to the vacation of the arbitration award, the Company no longer believes the loss related to this matter to be probable and thus the liability that was previously recorded in 2011 was reversed in the fourth quarter of 2012. The effect of this was recorded in discontinued operations on the Consolidated Statement of Income. For more information regarding discontinued operations, see Note 9.

Construction Materials Until the fall of 2011 when it discontinued active mining operations at the pit, JTL operated the Target Range Gravel Pit in Missoula County, Montana under a 1975 reclamation contract pursuant to the Montana Opencut Mining Act. In September 2009, the Montana DEQ sent a letter asserting JTL was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL filed a complaint in Montana First Judicial District Court in June 2010, seeking a declaratory order that the reclamation contract is a valid permit under the Montana Opencut Mining Act. The Montana DEQ filed an answer and counterclaim to the complaint in August 2011, alleging JTL was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than \$3.7 million plus not more than \$5,000 per day from the date of the counterclaim. The Company believes the operation of the Target Range Gravel Pit was conducted under a valid permit; however, the imposition of civil penalties is reasonably possible. The Company filed an application for amendment of its opencut mining permit and intends to resolve this matter through settlement or continuation of the Montana First Judicial District Court litigation.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel WBI Energy Midstream to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of WBI Energy Midstream's pipeline gathering systems in Montana. WBI Energy Midstream 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 WBI Energy Midstream into arbitration. In October 2010, the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. The Colorado Court of Appeals issued a decision on May 24, 2012, reversing the Colorado State District Court order compelling arbitration, vacating the final award and remanding the case to the Colorado State District Court to determine SourceGas's claims and WBI Energy Midstream's counterclaims. On remand of the matter to the Colorado State District Court, SourceGas may assert claims similar to those asserted in the arbitration proceeding.

In a related matter, Omimex filed a complaint against WBI Energy Midstream in Montana Seventeenth Judicial District Court in July 2010 alleging WBI Energy Midstream breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging WBI Energy Midstream breached obligations to operate its gathering system as a common carrier under United States and Montana law. WBI Energy Midstream removed the action to the United States District Court for the District of Montana. The parties subsequently settled the breach of contract claim and, subject to final determination on liability, stipulated to the damages on the common carrier claim, for amounts that are not material. A trial on the common carrier claim was held during July 2013, but a decision has not been issued.

Exploration and Production During the ordinary course of its business, Fidelity is subject to audit for various production related taxes by certain state and federal tax authorities for varying periods as well as claims for royalty obligations under lease agreements for oil and gas production. Disputes may exist regarding facts and questions of law relating to the tax and royalty obligations.

On May 15, 2013, Austin Holdings, LLC filed an action against Fidelity in Wyoming State District Court alleging Fidelity violated the Wyoming Royalty Payment Act and implied lease covenants by deducting production costs from and by failing to properly report and pay royalties for coalbed methane gas production in Wyoming. The plaintiff, in addition to declaratory and injunctive relief, seeks class certification for similarly situated persons and an unspecified amount of monetary damages on behalf of the class for unpaid royalties, interest, reporting violations and attorney fees. Fidelity believes it has meritorious defenses against class certification and the claims.

The Company also is subject to other litigation, and actual and potential claims in the ordinary course of its business which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. Accruals are based on the best information available but actual losses in future periods are affected by various factors making them uncertain. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above issues and other probable and reasonably possible losses in excess of the amounts accrued, while uncertain, will not have a material 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 contamination at a site in Eugene, Oregon which 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. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.7 million for remediation of this site. In January 2013, the OPUC approved Cascade's application to defer environmental remediation costs at the Eugene site for a period of 12 months starting November 30, 2012. Cascade received an order reauthorizing the deferred accounting for the 12 months starting November 30, 2013.

The second claim is for contamination at a site in Bremerton, Washington which 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. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.8 million for the remedial investigation, feasibility study and 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 for contamination at a site in Bellingham, 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. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers. The accruals related to these matters are reflected in regulatory assets.

Guarantees

Centennial guaranteed CEM's obligations under a construction contract. For more 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 oil and natural gas swap agreement obligations. There is no fixed maximum amount guaranteed in relation to the oil and natural gas swap agreements as the amount of the obligation is dependent upon oil and natural gas commodity prices. The amount of derivative activity entered into by the subsidiary is limited by corporate policy. The guarantees of the oil and natural gas swap agreements at March 31, 2014, expire in the years ranging from 2014 to 2015; however, Fidelity continues to enter into additional derivative instruments and, as a result, WBI Holdings from time to time may issue additional guarantees on these derivative instruments. The amount outstanding by Fidelity was $7.7 million and was reflected on the Consolidated Balance Sheet at March 31, 2014. 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 and certain other guarantees. At March 31, 2014, the fixed maximum amounts guaranteed under these agreements aggregated $48.7 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $26.8 million in 2014; $2.1 million in 2015; $700,000 in 2016; $600,000 in 2017; $500,000 in 2018; $500,000 in 2019; $13.5 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 $200,000 and was reflected on the Consolidated Balance Sheet at March 31, 2014. 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 and other agreements, some of which are guaranteed by other subsidiaries of the Company. At March 31, 2014, the fixed maximum amounts guaranteed under these letters of credit, aggregated $36.3 million. In 2014 and 2015, $7.0 million and $29.3 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at March 31, 2014.

WBI Holdings has an outstanding guarantee to WBI Energy Transmission. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At March 31, 2014, the fixed maximum amount guaranteed under this agreement was $4.0 million and is scheduled to expire in 2016. 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 $700,000. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at March 31, 2014, 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, 2014.

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, 2014, approximately $588.8 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary.

Dakota Prairie Refining, LLC On February 7, 2013, WBI Energy and Calumet formed a limited liability company, Dakota Prairie Refining, and entered into an operating agreement to develop, build and operate Dakota Prairie Refinery in southwestern North Dakota. WBI Energy and Calumet each have a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of $300 million, under the agreement are $150 million and $75 million, respectively. Capital commitments in excess of $300 million are expected to be shared equally between WBI Energy and Calumet. The total project cost is currently estimated at $350 million. Dakota Prairie Refining entered into a term loan for project debt financing of $75.0 million on April 22, 2013. The operating agreement provides for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt will be allocated to Calumet. Calumet's future cash distributions from Dakota Prairie Refining will be decreased by the principal and interest to be paid on the project debt, while the cash distributions to WBI Energy will not be decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan.

Dakota Prairie Refining has been determined to be a VIE, and the Company has determined that it is the primary beneficiary as it has an obligation to absorb losses that could be potentially significant to the VIE through WBI Energy's equity investment and Centennial's guarantee of the third-party term loan. Accordingly, the Company consolidates Dakota Prairie Refining in its financial statements and records a noncontrolling interest for Calumet's ownership interest.

Construction of Dakota Prairie Refinery began in early 2013 and the plant is not yet operational. Therefore, the results of operations of Dakota Prairie Refining did not have a material effect on the Company's Consolidated Statements of Income. The assets of Dakota Prairie Refining shall be used solely for the benefit of Dakota Prairie Refining. The total assets and liabilities of Dakota Prairie Refining reflected on the Company's Consolidated Balance Sheets were as follows:

	March 31, 2014	March 31, 2013	December 31, 2013
	(In thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$22,996	$10,793	$4,774
Other current assets	1,135	—	26
Total current assets	24,131	10,793	4,800
Net property, plant and equipment	207,260	27,356	172,073
Total assets	$231,391	$38,149	$176,873
LIABILITIES			
Current liabilities:			
Long-term debt due within one year	$3,000	$—	$3,000
Accounts payable	16,103	10,948	8,904
Taxes payable	113	—	5
Accrued compensation	164	—	26
Other accrued liabilities	580	—	461
Total current liabilities	19,960	10,948	12,396
Long-term debt	72,000	—	72,000
Total liabilities	$91,960	$10,948	$84,396

Fuel Contract On October 10, 2012, the Coyote Station entered into a new coal supply agreement with Coyote Creek that will replace a coal supply agreement expiring in May 2016. The new agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040.

The new coal supply agreement creates a variable interest in Coyote Creek due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so the price of the coal will cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of Coyote Creek as they would be required to buy the assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of Coyote Creek in that they are required to buy the entity at the end of the contract term at equity value. Although the Company has determined that Coyote Creek is a VIE, the Company has concluded that it is not the primary beneficiary of Coyote Creek because the authority to direct the activities of the entity is shared by the four unrelated owners of the Coyote Station, with no primary beneficiary existing. As a result, Coyote Creek is not required to be consolidated in the Company's financial statements.

At March 31, 2014, Coyote Creek was not yet operational. The assets and liabilities of Coyote Creek and exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage, at March 31, 2014, was $8.2 million.

Note 20 - Subsequent Events

Centennial entered into a two year $125.0 million term loan agreement with a variable interest rate on April 2, 2014.

The Company entered into a $150.0 million note purchase agreement on January 28, 2014. On April 15, 2014, the Company issued $50.0 million of Senior Notes with a due date of April 15, 2044, at an interest rate of 5.2 percent. The remaining $100.0 million of Senior Notes under the agreement will be issued on July 15, 2014, with due dates ranging from July 2024 to July 2026 at a weighted average interest rate of 4.3 percent.

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 16.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide safe and reliable competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities to retain, grow and expand their customer base through extensions of existing operations, including building and upgrading electric generation and transmission and natural gas systems, 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, system integrity and environmental regulations. These regulations can require substantial investment to upgrade facilities. 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 any new electric generating facilities, transmission lines and other service facilities are subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will 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.

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, investments in and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new energy sources for storage, gathering and transportation services; expansion of existing gathering, transmission and storage facilities; incremental expansion of pipeline capacity; expansion of midstream business to include liquid pipelines and processing/refining activities; and expansion of related energy services.

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 pipeline and energy services companies.

Exploration and 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 is focused on balancing the oil and natural gas commodity mix to

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maximize profitability with its goal 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; inflationary pressure on development and operating costs; and competition from other exploration and production 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; develop and recruit talented employees; and continue growth through organic and acquisition opportunities. 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, asphalt concrete, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Recruitment and retention of key personnel 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, positioning its operations for the resurgence in the private market, while continuing the emphasis on industrial, energy and public works projects.

Construction Services
Strategy Provide a superior return on investment by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; and focusing our efforts on projects that will permit higher margins while properly managing risk.

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.

For more 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 2013 Annual Report. For more 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,	
	2014	2013
	(Dollars in millions, where applicable)	
Electric	$11.0	$9.8
Natural gas distribution	27.3	32.5
Pipeline and energy services	4.3	2.3
Exploration and production	20.9	20.3
Construction materials and contracting	(23.6)	(20.6)
Construction services	16.6	11.7
Other	.3	.4
Intersegment eliminations	(.3)	—
Earnings before discontinued operations	56.5	56.4
Loss from discontinued operations, net of tax	—	(.1)
Earnings on common stock	$56.5	$56.3
Earnings per common share – basic:		
Earnings before discontinued operations	$.30	$.30
Discontinued operations, net of tax	—	—
Earnings per common share – basic	$.30	$.30
Earnings per common share – diluted:		
Earnings before discontinued operations	$.30	$.30
Discontinued operations, net of tax	—	—
Earnings per common share – diluted	$.30	$.30

Three Months Ended March 31, 2014 and 2013 Consolidated earnings for the quarter ended March 31, 2014, increased $200,000 from the comparable prior period largely due to:

- Higher workloads and margins in the Western region at the construction services business
- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, primarily due to higher volumes and prices, at the pipeline and energy services business
- Higher retail sales margins, largely the result of increased retail sales volumes of 10 percent and higher average realized rates, offset in part by higher operation and maintenance expense at the electric business

Partially offsetting these increases were:

- Higher operation and maintenance expense, largely related to higher payroll and benefit-related costs, and the absence in 2014 of the gain on the sale of Montana-Dakota's nonregulated appliance service and repair business in March 2013, offset in part by higher retail sales margins, largely resulting from higher average realized rates at the natural gas distribution business
- Lower earnings resulting from lower construction revenues and margins at the construction materials and contracting business

FINANCIAL AND OPERATING DATA

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

Electric

	Three Months Ended March 31, 2014	2013
	(Dollars in millions, where applicable)	
Operating revenues	$73.7	$64.6
Operating expenses:		
Fuel and purchased power	26.6	21.6
Operation and maintenance	18.4	16.4
Depreciation, depletion and amortization	8.5	8.6
Taxes, other than income	2.9	2.9
	56.4	49.5
Operating income	17.3	15.1
Earnings	$11.0	$9.8
Retail sales (million kWh)	928.9	842.6
Average cost of fuel and purchased power per kWh	$.027	$.024

Three Months Ended March 31, 2014 and 2013 Electric earnings increased $1.2 million (12 percent) due to higher retail sales margins, largely the result of increased retail sales volumes of 10 percent and higher average realized rates. Partially offsetting this increase was higher operation and maintenance expense, which includes $1.4 million (after tax) largely related to higher benefit-related costs and higher contract services.

Natural Gas Distribution

	Three Months Ended March 31, 2014		2013	
	(Dollars in millions, where applicable)			
Operating revenues	$374.2		$331.7	
Operating expenses:				
Purchased natural gas sold	257.3		213.4	
Operation and maintenance	37.9		34.1	
Depreciation, depletion and amortization	13.3		12.2	
Taxes, other than income	17.8		16.3	
	326.3		276.0	
Operating income	47.9		55.7	
Earnings	$27.3		$32.5	
Volumes (MMdk):				
Sales	45.3		44.9	
Transportation	39.3		38.2	
Total throughput	84.6		83.1	
Degree days (% of normal)*				
Montana-Dakota/Great Plains	107	%	98	%
Cascade	100	%	99	%
Intermountain	96	%	114	%

Average cost of natural gas, including transportation, per dk	$5.68	$4.75

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

Three Months Ended March 31, 2014 and 2013 Natural gas distribution earnings decreased $5.2 million (16 percent) due to:

- Higher operation and maintenance expense, which includes $3.2 million (after tax) largely related to higher payroll and benefit-related costs

- The absence in 2014 of the $2.9 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business in March 2013
- Higher depreciation, depletion and amortization expense of $700,000 (after tax), primarily resulting from higher property, plant and equipment balances

Partially offsetting these decreases were higher retail sales margins, largely resulting from approved rate increases effective in late 2013.

Pipeline and Energy Services

	Three Months Ended March 31,	
	2014	2013
	(Dollars in millions)	
Operating revenues	$61.9	$46.4
Operating expenses:		
Purchased natural gas sold	26.2	12.8
Operation and maintenance	16.8	17.2
Depreciation, depletion and amortization	7.1	7.2
Taxes, other than income	3.1	3.4
	53.2	40.6
Operating income	8.7	5.8
Earnings	$4.3	$2.3
Transportation volumes (MMdk)	52.5	36.8
Natural gas gathering volumes (MMdk)	9.5	9.9
Customer natural gas storage balance (MMdk):		
Beginning of period	26.7	43.7
Net withdrawal	(16.3)	(19.0)
End of period	10.4	24.7

Three Months Ended March 31, 2014 and 2013 Pipeline and energy services earnings increased $2.0 million (87 percent) due to:

- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, primarily due to higher volumes and prices
- Higher earnings of $600,000 (after tax) due to increased transportation volumes

These increases were partially offset by lower storage services revenue of $600,000 (after tax), largely due to lower average storage balances.

Results also reflect higher operating revenues and higher purchased natural gas sold, both related to higher natural gas prices.

Exploration and Production

	Three Months Ended March 31, 2014	2013
	(Dollars in millions, where applicable)	
Operating revenues:		
Oil	$113.6	$100.0
NGL	6.9	7.5
Natural gas	30.5	19.2
Realized gain (loss) on commodity derivatives	(6.8)	4.3
Unrealized loss on commodity derivatives	(6.7)	(5.8)
	137.5	125.2
Operating expenses:		
Operation and maintenance:		
Lease operating costs	24.2	20.8
Gathering and transportation	2.3	4.3
Other	11.8	10.2
Depreciation, depletion and amortization	49.5	43.1
Taxes, other than income:		
Production and property taxes	13.0	11.6
Other	.4	.3
	101.2	90.3
Operating income	36.3	34.9
Earnings	$20.9	$20.3
Production:		
Oil (MBbls)	1,280	1,118
NGL (MBbls)	164	201
Natural gas (MMcf)	5,278	6,713
Total production (MBOE)	2,324	2,438
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):		
Oil (per Bbl)	$88.74	$89.44
NGL (per Bbl)	$42.26	$37.33
Natural gas (per Mcf)	$5.77	$2.86
Average realized prices (including realized gain/loss on commodity derivatives):		
Oil (per Bbl)	$85.75	$91.87
NGL (per Bbl)	$42.26	$37.33
Natural gas (per Mcf)	$5.21	$3.10
Average depreciation, depletion and amortization rate, per BOE	$20.45	$16.90
Production costs, including taxes, per BOE:		
Lease operating costs	$10.39	$8.54
Gathering and transportation	1.01	1.76
Production and property taxes	5.58	4.74
	$16.98	$15.04

Three Months Ended March 31, 2014 and 2013 Exploration and production earnings increased $600,000 (3 percent) due to:

- Higher average realized natural gas prices of 102 percent, excluding gain/loss on commodity derivatives
- Increased oil production of 14 percent, primarily related to drilling activity in the Paradox Basin
- Lower gathering and transportation expenses of $1.2 million (after tax)

Partially offsetting these increases were:

- A loss of $7.0 million (after tax) resulting from a realized commodity derivative loss in 2014 compared to a realized commodity derivative gain in 2013
- Decreased natural gas production of 21 percent, largely due to the sale of non-strategic assets

- Higher depreciation, depletion and amortization expense of $4.0 million (after tax), primarily due to higher depletion rates
- Higher lease operating and general and administrative expenses of $3.2 million (after tax)
- Higher production taxes of $1.3 million (after tax), primarily resulting from higher revenues
- Decreased NGL production of 18 percent

Construction Materials and Contracting

	Three Months Ended March 31,	
	2014	2013
	(Dollars in millions)	
Operating revenues	$168.5	$166.3
Operating expenses:		
Operation and maintenance	175.8	166.6
Depreciation, depletion and amortization	17.6	19.0
Taxes, other than income	8.3	8.5
	201.7	194.1
Operating loss	(33.2)	(27.8)
Loss	$(23.6)	$(20.6)
Sales (000's):		
Aggregates (tons)	2,829	2,958
Asphalt (tons)	184	149
Ready-mixed concrete (cubic yards)	497	480

Three Months Ended March 31, 2014 and 2013 Construction materials and contracting experienced a seasonal first quarter loss of $23.6 million compared to a loss of $20.6 million a year ago (15 percent increased loss). The increased seasonal loss was the result of:

- Lower earnings of $3.1 million (after tax) resulting from lower construction revenues and margins
- Higher selling, general and administrative expenses of $1.7 million (after tax), including higher insurance costs

Partially offsetting the increased loss were higher earnings resulting from higher other product line margins.

Construction Services

	Three Months Ended March 31,	
	2014	2013
	(In millions)	
Operating revenues	$273.6	$231.4
Operating expenses:		
Operation and maintenance	234.0	198.4
Depreciation, depletion and amortization	3.2	3.0
Taxes, other than income	10.2	9.6
	247.4	211.0
Operating income	26.2	20.4
Earnings	$16.6	$11.7

Three Months Ended March 31, 2014 and 2013 Construction services earnings increased $4.9 million (42 percent), primarily due to higher workloads and margins in the Western region.

Other

	Three Months Ended March 31, 2014	2013
	(In millions)	
Operating revenues	$2.1	$2.2
Operating expenses:		
Operation and maintenance	1.2	1.3
Depreciation, depletion and amortization	.6	.5
	1.8	1.8
Operating income	.3	.4
Income from continuing operations	.3	.4
Loss from discontinued operations, net of tax	—	(.1)
Earnings	$.3	$.3

Intersegment Transactions

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

	Three Months Ended March 31, 2014	2013
	(In millions)	
Intersegment transactions:		
Operating revenues	$48.6	$36.2
Purchased natural gas sold	38.6	27.0
Operation and maintenance	9.2	9.2
Depreciation, depletion and amortization	.2	—
Earnings on common stock	.3	—

For more information on intersegment eliminations, see Note 16.

PROSPECTIVE INFORMATION

The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for 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 2013 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.

- Adjusted earnings per common share for 2014, diluted, are projected in the range of $1.50 to $1.65, excluding discontinued operations and the unrealized loss of $4.3 million (after tax) on commodity derivatives. Including these adjustments, GAAP earnings guidance for 2014 is in the same range. Unrealized commodity derivatives fair values can fluctuate causing actual GAAP earnings to vary accordingly.

The Company believes that these non-GAAP financial measures are useful because the items excluded are not indicative of the Company's continuing operating results. Also, the Company's management uses these non-GAAP financial measures as indicators for planning and forecasting future periods. The presentation of this additional information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

- The Company's long-term compound annual growth goals on earnings per share from operations are in the range of 7 to 10 percent.

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

- The Company focuses on creating value through vertical integration between its business units.
- Estimated gross capital expenditures for 2014 are approximately $1.2 billion, an increase from prior guidance with the inclusion of the Powder River Basin first quarter 2014 acquisition and associated drilling capital costs. The estimate excludes noncontrolling interest capital expenditures related to Dakota Prairie Refining.

Electric and natural gas distribution

- Rate base growth is projected to be approximately 9 percent compounded annually over the next five years, including plans for an approximate $1.3 billion capital investment program.
- Regulatory actions

The Company filed an application February 27, 2014, with the NDPSC requesting approval for a generation resource recovery rider to recover costs associated with the 88-MW simple-cycle natural gas turbine and associated facilities currently under construction, as discussed in Note 18.

The Company filed an application September 18, 2013, with the NDPSC for a natural gas rate increase, as discussed in Note 18.

The Company filed an application in February 2013 with the NDPSC for approval of an environmental cost recovery rider related to ongoing construction costs at the Big Stone Station for the installation of the BART air-quality control system. The Company's share of the cost for the installation is now estimated at approximately $90 million, down from the earlier estimate of $100 million, and is expected to be complete in 2015. The NDPSC approved the Company’s request for the environmental cost recovery rider and rates were implemented effective January 15, 2014. On April 8, 2014, the Company requested an update to the rider for actual costs through February 2014 and projected costs through June 2015 to be effective July 1, 2014. The NDPSC had earlier approved advance determination of prudence for recovery of costs on the system. For more information, see Note 18.

- Investments are being made in 2014 totaling approximately $70 million to serve the growing electric and natural gas customer base associated with the Bakken oil development where customer growth is substantially higher than the national average.
- The Company is engaged in a 30-mile, approximately $60 million natural gas line project into the Hanford Nuclear Site in Washington.
- The Company, along with a partner expects to build a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, about 160 miles. The Company’s share of the cost is estimated at approximately $170 million. The project is a MISO multi-value project. A route application was filed in August 2013 with the state of South Dakota, and in October 2013 with the state of North Dakota. A route permit hearing was held in North Dakota on April 1, 2014. A route permit hearing is scheduled in South Dakota on June 10, 2014. The project is expected to be complete in 2019.
- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors, with company- and customer-owned pipeline facilities designed to serve existing facilities served by fuel oil or propane, and to serve new customers.
- The Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system in the Pacific Northwest and Idaho.

Pipeline and energy services

- The Company, in conjunction with Calumet, formed Dakota Prairie Refining, to develop, build and operate Dakota Prairie Refinery. Construction began on the facility in late March 2013 and, when complete, it will process Bakken crude into diesel, which will be marketed within the Bakken region. Other by-products, naphtha and atmospheric tower bottoms, will be railed to other areas. The total project cost estimate is approximately $350 million, with a projected in-service date in late 2014. EBITDA for the first year of operation is projected to be in the range of $70 million to $90 million, to be shared equally with Calumet.
- In January 2014, the Company launched an open season to obtain capacity commitments on a proposed 375-mile natural gas pipeline from western North Dakota to northwestern Minnesota to transport natural gas to markets in eastern North Dakota,

Minnesota, Wisconsin, Michigan and other Midwest markets. The pipeline is expected to provide access to additional markets via interconnections with pipelines owned by Great Lakes Gas Transmission, Viking Gas Transmission and potentially TransCanada, in northwestern Minnesota. An interconnection with the Alliance Pipeline system in eastern North Dakota also is possible. Initially the pipeline would transport approximately 400 MMcf per day of natural gas and could be expanded to more than 500 MMcf per day. The project investment is estimated to be approximately $650 million. Following the open season and receipt of adequate capacity commitments and necessary permits and regulatory approvals, construction on the new pipeline could begin in 2016 with completion expected in 2017.

- On October 31, 2013, WBI Energy Transmission filed a Section 4 rate case with the FERC, as discussed in Note 18.

- The Company is engaged in various natural gas pipeline projects to be constructed in 2014, including connections for the planned Garden Creek II natural gas processing plant in the Bakken, an expansion of its transmission system to increase capacity to the Black Hills, and a 24-mile pipeline and related processing facilities to transport Fidelity's Paradox basin natural gas production. The total cost for these projects is approximately $50 million.

- The Company continues to pursue expansion of facilities and services offered to customers. Energy development within its geographic region is expanding, most notably in the Bakken area, where the Company owns an extensive natural gas pipeline system. Ongoing energy development is expected to continue to provide growth opportunities for this business.

Exploration and production

- The Company expects to spend approximately $670 million in capital expenditures in 2014, which is likely to be partially offset by planned asset sales later this year.

- For 2014, the Company expects a 15 to 20 percent increase in oil production. NGL production is expected to decline 20 to 25 percent and natural gas production is expected to be 25 to 30 percent lower compared to a year ago. The declines are primarily the result of the divestment of certain non-strategic natural gas-based properties in 2013 and the expected divestment of the Company's south Texas assets this year. The vast majority of the capital program is focused on growing oil production.

- The Company has a total of four operated drilling rigs deployed on its acreage in the Bakken and Paradox areas, with two rigs in each area.

- Bakken areas

The Company owns a total of approximately 121,000 net acres of leaseholds in Mountrail and Stark counties, North Dakota and Richland County, Montana. The Middle Bakken and Three Forks formations are targeted in North Dakota and the Red River formation is targeted in Montana.

Capital expenditures are expected to total approximately $130 million in 2014.

Net oil production for the first quarter 2014 was approximately 7,600 BOPD which is a 300 BOPD increase from the same 2013 period.

Alternative completion techniques, including increased stage count and cemented liners in the Middle Bakken (Mountrail County) and Three Forks (Mountrail and Stark counties) are being tested, with completion design changes to be finalized later in 2014.

- Paradox Basin, Utah

The Company owns approximately 130,000 net acres of leaseholds including its acquisition of 35,000 net acres of leaseholds in February 2014 and has an option to earn another 20,000 acres. The Company expects to further expand its acreage in the basin.

Capital expenditures are expected to total approximately $180 million in 2014.

Well costs range from $9 million to $12 million per well depending upon lateral lengths. With longer lateral lengths, estimated ultimate recoveries are expected to increase with the upper range now at 1.5 MMBbls of oil per well.

The CCU 12-1 well continues to exceed expectations with the well still flowing over 1,000 BOPD gross. It is anticipated that artificial lift facilities will be installed in the near future. Cumulative production is 690 MBbls of oil.

Net oil production for first quarter 2014 was approximately 3,575 BOPD, up 121 percent from first quarter 2013 and 22 percent higher than fourth quarter 2013. Current production is approximately 3,900 BOPD.

The Company's understanding of this play and the quality of the play continues to improve. It is anticipated that this field will play a key role in the Company's oil growth strategy.

- Powder River Basin, Wyoming

In March 2014, the Company acquired 24,500 net acres of leaseholds in Converse County, Wyoming.

Capital expenditures are expected to total approximately $270 million in 2014 including the acquisition costs, related closing adjustments and drilling capital.

At the end of March 2014, average net production was 1,630 BOE per day.

- Earnings guidance reflects estimated average NYMEX index prices for May through December 2014 in the range of $96 to $102 per Bbl of crude oil, and $4.25 to $4.75 per Mcf of natural gas. Estimated prices for NGLs are in the range of $37 to $40 per Bbl.

- Derivatives:

For April through June 2014, the Company has derivative instruments for 11,000 BOPD, July through September 2014 for 12,000 BOPD and 7,000 BOPD for October through December 2014, with a weighted average price of $95.11.

For April through December 2014, the Company has derivative instruments for 40,000 MMBtu of natural gas per day at a weighted average price of $4.10.

For 2015, the Company has a derivative instrument for 10,000 MMBtu of natural gas per day at $4.28.

The commodity derivative instruments that are in place as of April 30, 2014, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (Bbl/MMBtu)	Price (Per Bbl/MMBtu)
Crude Oil	Swap	NYMEX	4/14 - 6/14	91,000	$95.15
Crude Oil	Swap	NYMEX	4/14 - 6/14	91,000	$95.00
Crude Oil	Swap	NYMEX	4/14 - 6/14	91,000	$90.00
Crude Oil	Swap	NYMEX	4/14 - 6/14	91,000	$91.00
Crude Oil	Swap	NYMEX	4/14 - 6/14	91,000	$92.00
Crude Oil	Swap	NYMEX	4/14 - 6/14	91,000	$93.00
Crude Oil	Swap	NYMEX	4/14 - 6/14	91,000	$98.00
Crude Oil	Swap	NYMEX	4/14 - 6/14	91,000	$99.00
Crude Oil	Swap	NYMEX	4/14 - 6/14	91,000	$100.07
Crude Oil	Swap	NYMEX	4/14 - 12/14	275,000	$94.05
Crude Oil	Swap	NYMEX	4/14 - 12/14	275,000	$95.00
Crude Oil	Swap	NYMEX	7/14 - 9/14	184,000	$95.75
Crude Oil	Swap	NYMEX	7/14 - 9/14	184,000	$96.00
Crude Oil	Swap	NYMEX	7/14 - 9/14	92,000	$96.25
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$94.25
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$95.00
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$95.25
Crude Oil	Swap	NYMEX	7/14 - 12/14	368,000	$96.00
Natural Gas	Swap	NYMEX	4/14 - 12/14	5,500,000	$4.13
Natural Gas	Swap	NYMEX	4/14 - 12/14	2,750,000	$4.05
Natural Gas	Swap	NYMEX	4/14 - 12/14	2,750,000	$4.10
Natural Gas	Swap	NYMEX	1/15 - 12/15	3,650,000	$4.28

Construction materials and contracting

- Approximate work backlog as of March 31, 2014, was $653 million, compared to $589 million a year ago. Private work represents 9 percent of construction backlog and public work represents 91 percent of backlog. Bidding opportunities are good and additional backlog has been secured since March 31, 2014. The backlog includes a variety of projects such as highway grading, paving and underground projects, airports, bridge work, reclamation and harbor expansions.
- The Company's approximate backlog in North Dakota as of March 31, 2014, was $118 million. North Dakota backlog was $67 million a year ago.
- Projected revenues included in the Company's 2014 earnings guidance are in the range of $1.6 billion to $1.8 billion.
- The Company anticipates margins in 2014 to be in line with 2013 margins.
- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, wind towers and geothermal. Initiatives are aimed at capturing additional market share and expanding into new markets.
- As the country's sixth-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 seven labor contracts that Knife River was negotiating, as reported in Items 1 and 2 - Business and Properties - General in the 2013 Annual Report, four have been ratified. The three remaining contracts are still in negotiations.

Construction services

- Approximate work backlog as of March 31, 2014, was $397 million, compared to $465 million a year ago. Bidding opportunities are good and additional backlog has been secured since March 31, 2014. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including refinery work.

- The Company's approximate backlog in North Dakota as of March 31, 2014, was $7 million. The construction services business did not have any backlog in North Dakota a year ago.
- Projected revenues included in the Company's 2014 earnings guidance are in the range of $1.0 billion to $1.1 billion.
- The Company anticipates lower margins in 2014 compared to 2013 margins.
- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, substations, utility services, as well as solar. Initiatives are aimed at capturing additional market share and expanding into new markets.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

The Company's critical accounting policies involving significant estimates include impairment testing of oil and natural gas 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 2013 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2013 Annual Report.

LIQUIDITY AND CAPITAL COMMITMENTS

At March 31, 2014, the Company had cash and cash equivalents of $83.7 million and available capacity of $454.3 million under the outstanding credit facilities of the Company and its subsidiaries. The Company expects to meet its obligations for debt maturing within one year from various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt and the Company's equity securities.

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 2014 increased $163,000 from the comparable period in 2013. Lower working capital and other changes combined with higher operating cash flows at the construction services and pipeline and energy services businesses, were largely offset by lower operating cash flows at the construction materials and contracting, natural gas distribution and exploration and production businesses.

Investing activities Cash flows used in investing activities in the first three months of 2014 increased $209.5 million from the comparable period in 2013. The increase in cash flows used in investing activities was primarily due to higher acquisition-related capital expenditures at the exploration and production business.

Financing activities Cash flows provided by financing activities in the first three months of 2014 increased $222.7 million from the comparable period in 2013. The increase in cash flows provided by financing activities was primarily due to higher issuance of long-term debt of $197.5 million, primarily at the exploration and production business; as well as the issuance of $54.8 million of common stock. Partially offsetting this increase were higher dividends paid in 2014 compared to 2013 due to the acceleration of the first quarter 2013 quarterly common stock dividend to 2012.

Defined benefit pension plans

There were no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2013 Annual Report. For more information, see Note 17 and Part II, Item 7 in the 2013 Annual Report.

Capital expenditures

Net capital expenditures for the first three months of 2014 were $365.6 million and are estimated to be approximately $1.1 billion for 2014. Estimated capital expenditures include:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements

- Pipeline, gathering and other midstream projects
- Further development of existing properties, acquisition of additional leasehold acreage, exploratory drilling and proceeds from the sale of non-strategic assets at the exploration and production segment
- Power generation and transmission opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- The Company's proportionate share of Dakota Prairie Refinery at the pipeline and energy services segment
- 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 2014 capital expenditures referred to previously. The Company expects the 2014 estimated capital expenditures to be funded by various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt and the Company's equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed 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, 2014. 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 more information on the covenants, certain other conditions and cross-default provisions, see Part II, Item 8 - Note 9, in the 2013 Annual Report.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at March 31, 2014:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date
			(In millions)						
MDU Resources Group, Inc.	Commercial paper/ Revolving credit agreement	(a)	$125.0		$54.0	(b)	$—		10/4/17
Cascade Natural Gas Corporation	Revolving credit agreement		$50.0	(c)	$—		$2.2	(d)	7/9/18
Intermountain Gas Company	Revolving credit agreement		$65.0	(e)	$—		$—		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement	(f)	$500.0		$229.5	(b)	$—		6/8/17

(a) The commercial paper program is supported by a revolving credit agreement with various banks (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 letter of credit, as discussed in Note 19, reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $650 million). There were no amounts outstanding under the credit agreement.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of the construction businesses.

The following includes information related to the preceding table.

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in the Company's credit ratings have not limited, nor are currently expected to limit, the Company's ability to access the capital markets. If the Company were to experience a 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 4.8 times for the 12 months ended March 31, 2014 and December 31, 2013. Due to the $246.8 million after-tax noncash write-downs of oil and natural gas properties in 2012, earnings were insufficient by $17.2 million to cover fixed charges for the 12 months ended March 31, 2013. If the $246.8 million after-tax noncash write-downs were excluded, the coverage of fixed charges including preferred stock dividends would have been 4.6 times for the 12 months ended March 31, 2013.

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

Total equity as a percent of total capitalization was 58 percent, 59 percent and 60 percent at March 31, 2014 and 2013 and December 31, 2013, respectively. This ratio is calculated as the Company's total 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 total equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

On May 20, 2013, the Company entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 7.5 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. Sales of such common stock may not be made after February 28, 2016. Proceeds from the 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 issued 1.5 million shares of stock during the first quarter of 2014 under the Equity Distribution Agreement, receiving net proceeds of $50.1 million.

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The Company may sell all or a portion of such securities if warranted by market conditions and the Company's capital requirements. Any public offer and sale of such securities will be made only by means of a prospectus meeting the requirements of the Securities Act and the rules and regulations thereunder. The Company's board of directors currently has authorized the issuance and sale of up to an aggregate of $1.0 billion worth of such securities. The Company's board of directors reviews this authorization on a periodic basis and the aggregate amount of securities authorized may be increased in the future.

The Company entered into a $150.0 million note purchase agreement on January 28, 2014. On April 15, 2014, the Company issued $50.0 million of Senior Notes with a due date of April 15, 2044, at an interest rate of 5.2 percent. The remaining $100.0 million of Senior Notes under the agreement will be issued on July 15, 2014, with due dates ranging from July 2024 to July 2026 at a weighted average interest rate of 4.3 percent.

MDU Energy Capital, LLC On December 12, 2013, MDU Energy Capital entered into a $30.0 million note purchase agreement. MDU Energy Capital issued the Senior Notes under the agreement on January 27, 2014, with due dates ranging from January 2029 to January 2044 at a weighted average interest rate of 5.3 percent.

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued 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 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.

Centennial entered into two separate two year $125.0 million term loan agreements with variable interest rates on March 31, 2014 and April 2, 2014, respectively. These agreements contain customary covenants and default provisions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of Centennial's total debt to total capitalization to be greater than 65 percent. The covenants also include certain limitations on subsidiary indebtedness and restrictions on the sale of certain assets and on the making of certain loans and investments.

WBI Energy Transmission, Inc. WBI Energy Transmission has a $175.0 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at March 31, 2014, which reduced capacity under this uncommitted private shelf agreement.

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. For more information, see Note 10.

Centennial continues to guarantee CEM's obligations under a construction contract for an electric generating facility near Hobbs, New Mexico. For more information, see Note 19.

Contractual obligations and commercial commitments

There are no material changes in the Company's contractual obligations relating to estimated interest payments, operating leases, purchase commitments, derivatives, asset retirement obligations, uncertain tax positions and minimum funding requirements for its defined benefit plans for 2014 from those reported in the 2013 Annual Report.

The Company's contractual obligations relating to long-term debt at March 31, 2014, increased $251.3 million or 14 percent from December 31, 2013. As of March 31, 2014, the Company's contractual obligations related to long-term debt aggregated $2,105.8 million. The scheduled amounts of redemption (for the twelve months ended March 31, of each year listed) aggregate $12.2 million in 2015; $534.3 million in 2016; $154.9 million in 2017; $334.5 million in 2018; $126.8 million in 2019; and $943.1 million thereafter.

For more information on contractual obligations and commercial commitments, see Part II, Item 7 in the 2013 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.

For more information on derivative instruments and commodity price risk, see Part II, Item 7A in the 2013 Annual Report, the Consolidated Statements of Comprehensive Income and Notes 7 and 12.

Commodity price risk

Fidelity utilizes derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas on forecasted sales of oil and natural gas production.

The following table summarizes derivative agreements entered into by Fidelity as of March 31, 2014. These agreements call for Fidelity to receive fixed prices and pay variable prices.

(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Oil swap agreements maturing in 2014	$95.11	2,749	$(8,229)
Natural gas swap agreements maturing in 2014	$4.10	11,000	$(3,957)
Natural gas swap agreement maturing in 2015	$4.28	3,650	$330

Interest rate risk
There were no material changes to interest rate risk faced by the Company from those reported in the 2013 Annual Report.

At March 31, 2014, the Company had no outstanding interest rate hedges.

Foreign currency risk
The Company's investment in ECTE is exposed to market risks from changes in foreign currency exchange rates between the U.S. dollar and the Brazilian Real. For more information, see Part II, Item 8 - Note 4 in the 2013 Annual Report.

At March 31, 2014, 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, 2014, 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 19, which is incorporated herein 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 2013 Annual Report other than the risk related to environmental laws and regulations. These factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

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

The Company is subject to environmental laws and regulations affecting many aspects of its present and future operations including air quality, water quality, waste management and other environmental considerations. These laws and regulations can result in increased capital, operating and other costs, cause delays as a result of litigation and administrative proceedings, and create compliance, remediation, containment, monitoring and reporting obligations, particularly with regard to laws relating to electric generation operations and oil and natural gas development and processing. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities and private individuals may seek injunctive relief or other remedies to enforce applicable environmental laws and regulations with which they have differing interpretations of the Company's legal or regulatory compliance. The Company cannot predict the outcome (financial or operational) of any related litigation or administrative proceedings that may arise.

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

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

In December 2011, the EPA finalized the Mercury and Air Toxics Standards rules that will require reductions in mercury and other air emissions from coal- and oil-fired electric utility steam generating units. Montana-Dakota evaluated the pollution control technologies needed at its electric generation resources to comply with this final rule and determined that additional particulate matter control would be required to control non-mercury metal emissions at the Lewis & Clark Station near Sidney, Montana, and that such control could be accomplished through installation of a baghouse. Montana-Dakota reevaluated its options and determined the baghouse is not currently an economically effective means of compliance. Montana-Dakota now intends to comply with the rule by co-firing the plant with natural gas and lignite. Controls must be in place by April 16, 2015, or April 16, 2016, if a one-year extension is granted for completion of the pollution control project.

Hydraulic fracturing is an important common practice used by Fidelity that involves injecting water, sand, a water-thickening agent called guar, and trace amounts of chemicals, under pressure, into rock formations to stimulate oil, NGL and natural gas production. Fidelity is following state regulations for well drilling and completion, including regulations related to hydraulic fracturing and disposing of recovered fluids. Fracturing fluid constituents are reported on state or national websites. The EPA is developing a study to review the potential effects of hydraulic fracturing on underground sources of drinking water; the results of that study could impact future legislation or regulation. The BLM has released draft well stimulation regulations for hydraulic fracturing operations. If implemented, the BLM regulations would affect only Fidelity's operations on BLM-administered lands. If adopted as proposed, the BLM regulations, along with other legislative initiatives and regulatory studies, proceedings or initiatives at federal or state agencies that focus on the hydraulic fracturing process, could result in additional compliance, reporting and disclosure requirements. Future legislation or regulation could increase compliance and operating costs, as well as delay or inhibit the Company's ability to develop its oil, NGL and natural gas reserves.

On August 16, 2012, the EPA published a final NSPS rule for the oil and natural gas industry. The NSPS rule phases in over two years. The first phase was effective October 15, 2012, and primarily covers natural gas wells that are hydraulically fractured. Under the new rule, gas vapors or emissions from the natural gas wells must be captured or combusted utilizing a high-efficiency device. Additional reporting requirements and control devices covering oil and natural gas production equipment will be phased in for certain new oil and gas facilities with a final effective date of January 1, 2015. This new rule's impacts on Fidelity, WBI Energy Transmission and WBI Energy Midstream are not expected to be material and are likely to include implementation of recordkeeping, reporting and testing requirements and the acquisition and installation of required equipment.

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

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
January 1 through January 31, 2014	—			
February 1 through February 28, 2014	165,091	$33.70		
March 1 through March 31, 2014	—			
Total	165,091			

(1) Represents shares of common stock withheld by the Company to pay taxes in connection with the vesting of shares granted pursuant to the Long-Term Performance-Based Incentive Plan.
(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to purchase equity securities.

ITEM 4. MINE SAFETY DISCLOSURES

For information regarding mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K, see Exhibit 95 to this Form 10-Q, which is incorporated herein by reference.

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 7, 2014	BY:	/s/ Doran N. Schwartz Doran N. Schwartz Vice President and Chief Financial Officer
	BY:	/s/ Nathan W. Ring Nathan W. Ring Vice President, Controller and Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.	
+10(a)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 12, 2014
+10(b)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 13, 2014
10(c)	Purchase and Sale Agreement, dated February 10, 2014, dated effective October 1, 2013, between Fidelity Exploration & Production Company, Fidelity Oil Co. and Ballard Petroleum Holdings LLC
10(d)	Purchase and Sale Agreement, dated February 10, 2014, dated effective October 1, 2013, between Fidelity Exploration & Production Company, Fidelity Oil Co. and Maurice W. Brown Oil & Gas, LLC
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
95	Mine Safety Disclosures
101	The following materials from MDU Resources Group, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Consolidated Financial Statements, tagged in summary and detail

+ Management contract, compensatory plan or arrangement.

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