MDU RESOURCES GROUP INC
Form 10-Q
November 07, 2013

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 September 30, 2013

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 October 31, 2013: 188,830,529 shares.

DEFINITIONS

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

Abbreviation or Acronym	
2012 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2012
Alusa	Tecnica de Engenharia Electrica - Alusa
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
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
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 and amortization
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (2.5 percent ownership interest at September 30, 2013, 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
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
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
MTPSC	Montana Public Service Commission
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
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended

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 17.

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PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$192,103	$184,863	$843,670	$784,399
Exploration and production, construction materials and contracting, construction services and other	1,093,679	988,655	2,434,310	2,209,889
Total operating revenues	1,285,782	1,173,518	3,277,980	2,994,288
Operating expenses:				
Fuel and purchased power	19,983	17,634	59,760	51,247
Purchased natural gas sold	35,826	35,199	305,268	279,038
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	64,078	67,830	206,808	188,945
Exploration and production, construction materials and contracting, construction services and other	870,252	793,850	1,925,762	1,793,347
Depreciation, depletion and amortization	99,966	91,850	288,816	260,858
Taxes, other than income	45,804	41,090	145,784	132,017
Write-down of oil and natural gas properties (Note 5)	—	160,100	—	160,100
Total operating expenses	1,135,909	1,207,553	2,932,198	2,865,552
Operating income (loss)	149,873	(34,035)	345,782	128,736
Earnings (loss) from equity method investments	(61)	2,388	(380)	4,025
Other income	2,326	1,702	5,003	4,050
Interest expense	21,012	19,840	63,312	56,929
Income (loss) before income taxes	131,126	(49,785)	287,093	79,882
Income taxes	46,576	(20,253)	99,559	24,516
Income (loss) from continuing operations	84,550	(29,532)	187,534	55,366
Income (loss) from discontinued operations, net of tax (Note 11)	(118)	(139)	(254)	4,867
Net income (loss)	84,432	(29,671)	187,280	60,233
Net loss attributable to noncontrolling interest	(24)	—	(204)	—
Dividends declared on preferred stocks	171	171	514	514
Earnings (loss) on common stock	$84,285	$(29,842)	$186,970	$59,719
Earnings (loss) per common share -- basic:				
Earnings (loss) before discontinued operations	$.45	$(.16)	$.99	$.29
Discontinued operations, net of tax	—	—	—	.03
Earnings (loss) per common share -- basic	$.45	$(.16)	$.99	$.32
Earnings (loss) per common share -- diluted:				

Earnings (loss) before discontinued operations	$.44	$(.16)	$.99	$.29
Discontinued operations, net of tax	—	—	—	.03
Earnings (loss) per common share -- diluted	$.44	$(.16)	$.99	$.32
Dividends declared per common share	$.1725	$.1675	$.5175	$.5025
Weighted average common shares outstanding - basic	188,831	188,831	188,831	188,824
Weighted average common shares outstanding - diluted	189,638	188,831	189,634	189,029

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Net income (loss)	$84,432	$(29,671)	$187,280	$60,233
Other comprehensive income (loss):				
Net unrealized gain (loss) on derivative instruments qualifying as hedges:				
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $0 and $(5,377) for the three months ended and $(3,116) and $4,570 for the nine months ended in 2013 and 2012, respectively	—	(9,125)	(5,594)	7,962
Reclassification adjustment for gain on derivative instruments included in net income, net of tax of $(297) and $(4,570) for the three months ended and $(2,246) and $(4,126) for the nine months ended in 2013 and 2012, respectively	(510)	(7,782)	(3,678)	(7,029)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(510)	(16,907)	(9,272)	933
Net unrealized gain (loss) on available-for-sale investments:				
Net unrealized gain (loss) on available-for-sale investments arising during the period, net of tax of $(5) and $4 for the three months ended and $(106) and $(22) for the nine months ended in 2013 and 2012, respectively	(10)	7	(197)	(41)
Reclassification adjustment for loss on available-for-sale investments included in net income, net of tax of $20 and $17 for the three months ended and $63 and $54 for the nine months ended in 2013 and 2012, respectively	38	32	117	101
Net unrealized gain (loss) on available-for-sale investments	28	39	(80)	60
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $166 and $1,027 for the three and nine months ended in 2013	271	—	1,344	—
Foreign currency translation adjustment:				
Foreign currency translation adjustment recognized during the period, net of tax of $(12) and $(10) for the three months ended and $(209) and $(275) for the nine months ended in 2013 and 2012, respectively	(20)	(8)	(351)	(443)
Reclassification adjustment for loss on foreign currency translation adjustment included in net income, net of tax of $70 and $2 for the three months ended and $70 and $2 for the nine months ended in 2013 and 2012, respectively	115	3	143	3
Foreign currency translation adjustment	95	(5)	(208)	(440)
Other comprehensive income (loss)	(116)	(16,873)	(8,216)	553
Comprehensive income (loss)	84,316	(46,544)	179,064	60,786
Comprehensive loss attributable to noncontrolling interest	(24)	—	(204)	—
Comprehensive income (loss) attributable to common stockholders	$84,340	$(46,544)	$179,268	$60,786

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

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

	September 30, 2013	September 30, 2012	December 31, 2012
(In thousands, except shares and per share amounts)			
ASSETS			
Current assets:			
Cash and cash equivalents	$66,174	$74,242	$49,042
Receivables, net	787,311	743,274	678,123
Inventories	314,571	315,767	317,415
Deferred income taxes	26,284	25,345	22,846
Commodity derivative instruments	4,373	19,193	18,304
Prepayments and other current assets	56,257	71,579	42,351
Total current assets	1,254,970	1,249,400	1,128,081
Investments	108,664	102,139	103,243
Property, plant and equipment	8,651,334	8,129,872	8,107,751
Less accumulated depreciation, depletion and amortization	3,796,052	3,546,927	3,608,912
Net property, plant and equipment	4,855,282	4,582,945	4,498,839
Deferred charges and other assets:			
Goodwill	636,039	636,039	636,039
Other intangible assets, net	14,092	18,015	17,129
Other	298,061	314,133	299,160
Total deferred charges and other assets	948,192	968,187	952,328
Total assets	$7,167,108	$6,902,671	$6,682,491
LIABILITIES AND EQUITY			
Current liabilities:			
Short-term borrowings	$7,000	$11,000	$28,200
Long-term debt due within one year	44,024	240,564	134,108
Accounts payable	437,740	402,241	388,015
Taxes payable	80,392	54,903	46,475
Dividends payable	32,745	31,800	171
Accrued compensation	62,746	48,792	48,448
Commodity derivative instruments	9,740	2,072	—
Other accrued liabilities	171,420	233,773	204,698
Total current liabilities	845,807	1,025,145	850,115
Long-term debt	1,967,872	1,502,413	1,610,867
Deferred credits and other liabilities:			
Deferred income taxes	808,011	797,249	755,102
Other liabilities	794,928	834,934	818,159
Total deferred credits and other liabilities	1,602,939	1,632,183	1,573,261
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			
	189,369	189,369	189,369

Shares issued - 189,369,450 at September 30, 2013 and 2012 and December 31, 2012			
Other paid-in capital	1,041,787	1,038,066	1,039,080
Retained earnings	1,546,000	1,550,569	1,457,146
Accumulated other comprehensive loss	(56,937)	(46,448)	(48,721)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,716,593	2,727,930	2,633,248
Total stockholders' equity	2,731,593	2,742,930	2,648,248
Noncontrolling interest	18,897	—	—
Total equity	2,750,490	2,742,930	2,648,248
Total liabilities and equity	$7,167,108	$6,902,671	$6,682,491

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

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

	Nine Months Ended September 30,	
	2013	2012
	(In thousands)	
Operating activities:		
Net income	$187,280	$60,233
Income (loss) from discontinued operations, net of tax	(254)	4,867
Income from continuing operations	187,534	55,366
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	288,816	260,858
Earnings (loss), net of distributions, from equity method investments	1,736	(1,086)
Deferred income taxes	46,212	40,310
Unrealized loss on commodity derivatives	5,379	523
Write-down of oil and natural gas properties	—	160,100
Changes in current assets and liabilities, net of acquisitions:		
Receivables	(107,482)	(89,596)
Inventories	1,562	(40,386)
Other current assets	(15,397)	(18,512)
Accounts payable	25,817	21,811
Other current liabilities	18,680	(32,994)
Other noncurrent changes	(24,149)	(20,206)
Net cash provided by continuing operations	428,708	336,188
Net cash provided by (used in) discontinued operations	254	(6,826)
Net cash provided by operating activities	428,962	329,362
Investing activities:		
Capital expenditures	(648,465)	(629,776)
Acquisitions, net of cash acquired	—	(67,253)
Net proceeds from sale or disposition of property and other	40,985	31,090
Investments	218	11,188
Proceeds from sale of equity method investment	1,896	2,394
Net cash used in continuing operations	(605,366)	(652,357)
Net cash provided by discontinued operations	—	—
Net cash used in investing activities	(605,366)	(652,357)
Financing activities:		
Issuance of short-term borrowings	5,000	2,900
Issuance of long-term debt	497,318	400,443
Repayment of long-term debt	(255,980)	(73,459)
Proceeds from issuance of common stock	—	88
Dividends paid	(65,660)	(95,394)
Excess tax benefit on stock-based compensation	—	26
Contribution from noncontrolling interest	13,000	—
Net cash provided by continuing operations	193,678	234,604
Net cash provided by discontinued operations	—	—

Net cash provided by financing activities	193,678	234,604
Effect of exchange rate changes on cash and cash equivalents	(142)	(139)
Increase (decrease) in cash and cash equivalents	17,132	(88,530)
Cash and cash equivalents -- beginning of year	49,042	162,772
Cash and cash equivalents -- end of period	$66,174	$74,242

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

MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

September 30, 2013 and 2012
(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 2012 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 2012 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 September 30, 2013, 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 consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $31.1 million, $35.1 million and $34.3 million as of September 30, 2013 and 2012, and December 31, 2012, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of September 30, 2013 and 2012, and December 31, 2012, was $9.6 million, $10.5 million and $10.8 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:

	September 30, 2013	September 30, 2012	December 31, 2012
	(In thousands)		
Aggregates held for resale	$104,784	$88,632	$87,715
Asphalt oil	43,078	47,084	67,480
Materials and supplies	71,370	75,551	69,390
Merchandise for resale	23,713	30,827	31,172
Natural gas in storage (current)	37,689	41,091	29,030

Other	33,937	32,582	32,628
Total	$314,571	$315,767	$317,415

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 $48.6 million, $50.3 million, and $49.7 million at September 30, 2013 and 2012, and December 31, 2012, respectively.

Note 5 - Oil and natural gas properties
The Company uses the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and amortized on

the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices. If capitalized costs, less accumulated amortization and related deferred income taxes, exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

The Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at September 30, 2012, largely the result of lower SEC Defined Prices, primarily lower natural gas prices. Accordingly, the Company was required to write down its oil and natural gas producing properties. The noncash write-down amounted to $160.1 million ($100.9 million after tax) for the three and nine months ended September 30, 2012.

The Company hedged a portion of its oil and natural gas production and the effects of the cash flow hedges were used in determining the full-cost ceiling at September 30, 2012. The Company would have recognized an additional write-down of its oil and natural gas properties of $19.5 million ($12.3 million after tax) at September 30, 2012, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 14.

At September 30, 2013, the Company's full-cost ceiling exceeded the Company's capitalized costs. However, there is risk that lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in additional future noncash write-downs of the Company's oil and natural gas properties.

Note 6 - Impairment of long-lived assets

During the second quarters of 2013 and 2012, the Company recognized impairments of coalbed natural gas gathering assets at the pipeline and energy services segment of $14.5 million ($9.0 million after tax) and $2.7 million ($1.7 million after tax), respectively, which are recorded in operation and maintenance expense on the Consolidated Statements of Income. The impairments are related to coalbed natural gas gathering assets located in Wyoming and Montana where there has been a significant decline in natural gas development and production activity largely due to low natural gas prices. The coalbed natural gas gathering assets were written down to fair value that was determined using the income approach. For more information on this nonrecurring fair value measurement, see Note 15.

Note 7 - 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Weighted average common shares outstanding - basic	188,831	188,831	188,831	188,824

Effect of dilutive stock options and performance share awards	807	—	803	205
Weighted average common shares outstanding - diluted	189,638	188,831	189,634	189,029
Shares excluded from the calculation of diluted earnings per share	—	434	—	—

Note 8 - Cash flow information

Cash expenditures for interest and income taxes were as follows:

	Nine Months Ended September 30, 2013	2012
	(In thousands)	
Interest, net of amount capitalized	$60,281	$57,956
Income taxes paid	$30,262	$3,210

Noncash investing transactions were as follows:

	September 30, 2013	2012
	(In thousands)	
Property, plant and equipment additions in accounts payable	$85,646	$68,636

Note 9 - New accounting standards

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income In February 2013, the FASB issued guidance on the reporting of amounts reclassified out of accumulated other comprehensive income. This guidance requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required to be reclassified in its entirety to net income. Entities may present this information either on the face of the statement where net income is presented or in the notes. This guidance was effective for the Company on January 1, 2013, and is to be applied prospectively. The guidance required additional disclosures, however it did not impact the Company's results of operations, financial position or cash flows.

Disclosures about Offsetting Assets and Liabilities In December 2011, the FASB issued guidance on the disclosure requirements related to balance sheet offsetting. The new disclosure requirements relate to the nature of an entity's rights of offset and related arrangements associated with its financial instruments and derivative instruments. In January 2013, the FASB issued guidance clarifying the scope of the disclosures related to balance sheet offsetting. The amendments clarify that this guidance only applies to derivative instruments, repurchase agreements and securities lending transactions that are either offset or subject to an enforceable master netting arrangement. The guidance was effective for the Company on January 1, 2013, and must be applied retrospectively. The guidance required additional disclosures, however it did not impact the Company's results of operations, financial position or cash flows.

Note 10 - Comprehensive income (loss)

The after-tax changes in the components of accumulated other comprehensive loss as of September 30, 2013, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Net Unrealized Gain (Loss) on Available-for-sale Investments	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at December 31, 2012	$6,018	$ 119	$(54,347)	$(511)	$(48,721)
Other comprehensive income (loss) before reclassifications	(5,594)	(197)	—	(351)	(6,142)

Amounts reclassified from accumulated other comprehensive loss	(3,678)	117	1,344	143	(2,074)
Net current-period other comprehensive income (loss)	(9,272)	(80)	1,344	(208)	(8,216)
Balance at September 30, 2013	$(3,254)	$ 39	$(53,003)	$(719)	$(56,937)

Reclassifications out of accumulated other comprehensive loss were as follows:

	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for gain (loss) on derivative instruments included in net income			
Commodity derivative instruments	$ 1,007	$ 6,903	Operating revenues
Interest rate derivative instruments	(200)	(979)	Interest expense
	807	5,924	
	(297)	(2,246)	Income taxes
	510	3,678	
Amortization of postretirement liability losses included in net periodic benefit cost	(437)	(2,371)	(a)
	166	1,027	Income taxes
	(271)	(1,344)	
Reclassification adjustment for loss on available-for-sale investments included in net income	(58)	(180)	Other income
	20	63	Income taxes
	(38)	(117)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income	(185)	(213)	Earnings (loss) from equity method investments
	70	70	Earnings (loss) from equity method investments
	(115)	(143)	
Total reclassifications	$ 86	$ 2,074	

(a) Included in net periodic benefit cost (credit). For more information, see Note 18.

Note 11 - 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 and has accrued liabilities related to this matter. In the second quarter of 2012, discontinued operations reflected a net benefit largely related to estimated insurance recoveries related to this matter. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For more information, see Note 20.

Note 12 - 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 September 30, 2013, 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 interest 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 remaining interest in ECTE is being purchased 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 and 2012. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE. The Company's remaining ownership interest in ECTE is being accounted for under the cost method.

At September 30, 2012 and December 31, 2012, the equity method investments had total assets of $110.6 million and $129.0 million, respectively, and long-term debt of $28.2 million and $65.5 million, respectively. The Company's investment in its equity method investments was approximately $7.4 million and $6.9 million, including undistributed earnings of $4.1 million and $3.4 million, at September 30, 2012 and December 31, 2012, respectively.

Note 13 - Goodwill and other intangible assets

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

Nine Months Ended September 30, 2013	Balance as of January 1, 2013*	Goodwill Acquired During the Year	Balance as of September 30, 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.

Nine Months Ended September 30, 2012	Balance as of January 1, 2012*	Goodwill Acquired During the Year**	Balance as of September 30, 2012*
	(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	103,168	1,108	104,276
Total	$634,931	$1,108	$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.

** Includes contingent consideration that was not material related to an acquisition in a prior period.

Year Ended December 31, 2012	Balance as of January 1, 2012*	Goodwill Acquired During the Year**	Balance as of December 31, 2012*
	(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	103,168	1,108	104,276
Total	$634,931	$1,108	$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.

** Includes contingent consideration that was not material related to an acquisition in a prior period.

Other amortizable intangible assets were as follows:

	September 30, 2013	September 30, 2012	December 31, 2012
	(In thousands)		
Customer relationships	$21,310	$21,310	$21,310
Accumulated amortization	(13,221)	(11,192)	(11,701)
	8,089	10,118	9,609
Noncompete agreements	6,186	7,236	7,236
Accumulated amortization	(4,706)	(5,198)	(5,326)
	1,480	2,038	1,910
Other	10,995	10,979	10,979
Accumulated amortization	(6,472)	(5,120)	(5,369)
	4,523	5,859	5,610
Total	$14,092	$18,015	$17,129

Amortization expense for amortizable intangible assets for the three and nine months ended September 30, 2013, was $1.2 million and $3.0 million, respectively. Amortization expense for amortizable intangible assets for the three and nine months ended September 30, 2012, was $1.0 million and $2.9 million, respectively. Estimated amortization expense for amortizable intangible assets is $3.7 million in 2013, $3.4 million in 2014, $2.6 million in 2015, $2.2 million in 2016, $1.9 million in 2017 and $3.3 million thereafter.

Note 14 - 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 September 30, 2013, the Company had no outstanding foreign currency or interest rate hedges. The following information should be read in conjunction with Notes 1 and 7 in the Company's Notes to Consolidated Financial Statements in the 2012 Annual Report.

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.

Cascade

Cascade has historically utilized natural gas swap agreements to manage a portion of its regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. As of September 30, 2013 and December 31, 2012, Cascade has no outstanding swap agreements. As of September 30, 2012, Cascade held a natural gas swap agreement with total forward notional volumes of 31,000 MMBtu. Periodic changes in the fair market value of the derivative instruments are recorded on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade either pays or receives settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the three and nine months ended September 30, 2012, the change in the fair market value of the derivative instrument of $175,000 and $384,000, respectively, was recorded as a decrease to regulatory assets.

Cascade's derivative instrument contains a cross-default provision that states that if Cascade fails to pay certain of its indebtedness, in excess of specified amounts, the counterparty may require early settlement or termination of the derivative instrument in a liability position. The fair value of Cascade's derivative instrument with the credit-risk-related contingent feature that was in a liability position at September 30, 2012, was $53,000. The aggregate fair value of assets that would have been needed to settle the instrument immediately if the credit-risk-related contingent feature were triggered on September 30, 2012, was $53,000.

Fidelity
At September 30, 2013 and 2012, and December 31, 2012, Fidelity held oil swap and collar agreements with total forward notional volumes of 3.9 million, 3.3 million and 2.6 million Bbl, respectively, and natural gas swap agreements with total forward notional volumes of 16.5 million, 8.2 million and 11.0 million MMBtu, respectively. In addition, at September 30, 2012, Fidelity held natural gas basis swap agreements with total forward notional volumes of 874,000 MMBtu. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas and basis differentials 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 15 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 September 30, 2013, Centennial had no outstanding interest rate swap agreements. At September 30, 2012 and December 31, 2012, Centennial held interest rate swap agreements with total notional amounts of $60.0 million and $50.0 million, respectively, 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Commodity derivatives designated as cash flow hedges:				
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	$—	$(8,622)	$(6,153)	$9,822
Amount of gain reclassified from accumulated other comprehensive loss into operating revenues (effective portion), net of tax	(634)	(7,788)	(4,349)	(7,056)
Amount of loss recognized in operating revenues (ineffective portion), before tax	—	(529)	(1,422)	(917)
Interest rate derivatives designated as cash flow hedges:				
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	—	(503)	559	(1,860)
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	124	6	671	27
Amount of loss recognized in interest expense (ineffective portion), before tax	—	—	(769)	—
Commodity derivatives not designated as hedging instruments:				
Amount of gain (loss) recognized in operating revenues, before tax	(12,594)	(654)	(3,957)	394

Based on September 30, 2013, fair values, over the next 12 months net gains of approximately $28,000 (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 derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates fail to pay certain of their indebtedness, in excess of specified amounts, the counterparties may require early settlement or termination of the derivative instruments in liability positions. The aggregate fair value of Fidelity's derivative instruments with credit-risk-related contingent features that are in a liability position at September 30, 2013 and 2012, and December 31, 2012, were $9.9 million, $9.9 million and $6.3 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 September 30, 2013 and 2012, and December 31, 2012, were $9.9 million, $9.9 million and $6.3 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 September 30, 2013	Fair Value at September 30, 2012	Fair Value at December 31, 2012
		(In thousands)		
Designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$—	$18,619	$18,084
	Other assets - noncurrent	—	3,463	—
		—	22,082	18,084
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	4,373	574	220
	Other assets - noncurrent	1,771	63	—
		6,144	637	220
Total asset derivatives		$6,144	$22,719	$18,304

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at September 30, 2013	Fair Value at September 30, 2012	Fair Value at December 31, 2012
		(In thousands)		
Designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$—	$1,958	$—
	Other liabilities - noncurrent	—	83	—
Interest rate derivatives	Other accrued liabilities	—	7,779	6,255
		—	9,820	6,255
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	9,740	114	—
	Other liabilities - noncurrent	149	—	—
		9,889	114	—
Total liability derivatives		$9,889	$9,934	$6,255

All of the Company's commodity and interest rate derivative instruments at September 30, 2013 and 2012, and December 31, 2012, 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:

September 30, 2013	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$6,144	$(4,939)	$1,205
Total assets	$6,144	$(4,939)	$1,205
Liabilities:			

Commodity derivatives	$9,889	$(4,939)	$4,950
Total liabilities	$9,889	$(4,939)	$4,950

September 30, 2012	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$22,719	$(2,102)	$20,617
Total assets	$22,719	$(2,102)	$20,617
Liabilities:			
Commodity derivatives	$2,155	$(2,102)	$53
Interest rate derivatives	7,779	—	7,779
Total liabilities	$9,934	$(2,102)	$7,832

December 31, 2012	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$18,304	$—	$18,304
Total assets	$18,304	$—	$18,304
Liabilities:			
Interest rate derivatives	$6,255	$—	$6,255
Total liabilities	$6,255	$—	$6,255

Note 15 - 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 $58.1 million, $48.4 million and $48.9 million, as of September 30, 2013 and 2012, and December 31, 2012, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments were $4.1 million and $9.2 million for the three and nine months ended September 30, 2013, respectively. The net unrealized gains on these investments was $2.4 million and $4.7 million for the three and nine months ended September 30, 2012. 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:

September 30, 2013	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$ 8,051	$ 70	$ (20)	$ 8,101
U.S. Treasury securities	1,912	15	(4)	1,923
Total	$ 9,963	$ 85	$ (24)	$ 10,024

September 30, 2012	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$ 8,391	$ 175	$ (2)	$ 8,564
U.S. Treasury securities	1,758	47	—	1,805
Total	$ 10,149	$ 222	$ (2)	$ 10,369

December 31, 2012	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$ 8,054	$ 144	$ (3)	$ 8,195
U.S. Treasury securities	1,763	43	—	1,806
Total	$ 9,817	$ 187	$ (3)	$ 10,001

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 and nine months ended September 30, 2013 and 2012, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at September 30, 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 September 30, 2013
	(In thousands)			
Assets:				
Money market funds	$—	$21,019	$—	$21,019
Insurance contract*	—	58,142	—	58,142
Available-for-sale securities:				
Mortgage-backed securities	—	8,101	—	8,101
U.S. Treasury securities	—	1,923	—	1,923
Commodity derivative instruments	—	6,144	—	6,144
Total assets measured at fair value	$—	$95,329	$—	$95,329
Liabilities:				
Commodity derivative instruments	$—	$9,889	$—	$9,889
Total liabilities measured at fair value	$—	$9,889	$—	$9,889

* 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 and other investments.

	Fair Value Measurements at September 30, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at September 30, 2012
	(In thousands)			
Assets:				
Money market funds	$—	$21,816	$—	$21,816
Insurance contract*	—	48,384	—	48,384
Available-for-sale securities:				
Mortgage-backed securities	—	8,564	—	8,564
U.S. Treasury securities	—	1,805	—	1,805
Commodity derivative instruments	—	22,719	—	22,719
Total assets measured at fair value	$—	$103,288	$—	$103,288
Liabilities:				
Commodity derivative instruments	$—	$2,155	$—	$2,155
Interest rate derivative instruments	—	7,779	—	7,779

Total liabilities measured at fair value	$—	$9,934	$—	$9,934

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

	Fair Value Measurements at December 31, 2012, 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, 2012
	(In thousands)			
Assets:				
Money market funds	$—	$24,240	$—	$24,240
Insurance contract*	—	48,898	—	48,898
Available-for-sale securities:				
Mortgage-backed securities	—	8,195	—	8,195
U.S. Treasury securities	—	1,806	—	1,806
Commodity derivative instruments	—	18,304	—	18,304
Total assets measured at fair value	$—	$101,443	$—	$101,443
Liabilities:				
Interest rate derivative instruments	$—	$6,255	$—	$6,255
Total liabilities measured at fair value	$—	$6,255	$—	$6,255

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

The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including long-lived asset impairments. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company reviews the carrying value of its long-lived assets, excluding goodwill and oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable. During the second quarters of 2013 and 2012, coalbed natural gas gathering assets were reviewed for impairment and found to be impaired and were written down to their estimated fair value using the income approach. Under this approach, fair value is determined by using the present value of future estimated cash flows. The factors used to determine the estimated future cash flows include, but are not limited to, internal estimates of gathering revenue, future commodity prices and operating costs and equipment salvage values. The estimated cash flows are discounted using a rate that approximates the weighted average cost of capital of a market participant. These fair value inputs are not typically observable. At June 30, 2012, certain coalbed natural gas gathering assets were written down to the nonrecurring fair value measurement of $2.5 million. At June 30, 2013, additional coalbed natural gas gathering assets were written down to the nonrecurring fair value measurement of $9.7 million. The fair value of these coalbed natural gas gathering assets have been categorized as Level 3 (Significant Unobservable Inputs) in the fair value hierarchy.

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 September 30, 2013	$2,011,896	$2,106,887
Long-term debt at September 30, 2012	$1,742,977	$1,906,673
Long-term debt at December 31, 2012	$1,744,975	$1,888,135

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

Note 16 - Income taxes

In connection with the income tax examination for the 2007 through 2009 tax years, the Company recorded income tax expense of $2.2 million for unrecognized tax positions in the first quarter of 2012.

In addition, the Company had a reduction of deferred income tax expense of $2.5 million in the first quarter of 2012, due to a deferred income tax rate reduction related to state income tax apportionment.

It is likely that substantially all of the unrecognized tax benefits of $14.9 million, as well as interest, at September 30, 2013, will be settled in the next 12 months due to the anticipated settlement of federal and state audits.

In September 2013, the Internal Revenue Service released final regulations relating to the capitalization of tangible personal property which are effective for tax years beginning on or after January 1, 2014. The Company does not expect these new regulations to have a material effect on its results of operations, financial position or cash flows.

Note 17 - 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 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 regions of the United States and in and around the Gulf of Mexico.

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

The 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 2012 Annual Report. Information on the Company's businesses was as follows:

Three Months Ended September 30, 2013	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$68,314	$—	$11,417
Natural gas distribution	77,417	—	(11,204)
Pipeline and energy services	46,372	4,906	5,310
	192,103	4,906	5,523
Exploration and production	119,234	10,714	17,434
Construction materials and contracting	706,982	7,422	49,159
Construction services	267,038	3,097	12,154
Other	425	1,859	1,217
	1,093,679	23,092	79,964
Intersegment eliminations	—	(27,998)	(1,202)
Total	$1,285,782	$—	$84,285

Three Months Ended September 30, 2012	External Operating Revenues	Inter-segment Operating Revenues	Loss on Common Stock
	(In thousands)		
Electric	$63,492	$—	$11,000
Natural gas distribution	80,069	—	(8,782)
Pipeline and energy services	41,302	7,046	3,273
	184,863	7,046	5,491
Exploration and production	100,380	8,076	(87,748)
Construction materials and contracting	641,500	8,508	41,889
Construction services	246,358	834	9,863
Other	417	1,948	663
	988,655	19,366	(35,333)
Intersegment eliminations	—	(26,412)	—
Total	$1,173,518	$—	$(29,842)

Nine Months Ended September 30, 2013	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$189,949	$—	$25,652
Natural gas distribution	536,756	—	15,420
Pipeline and energy services	116,965	31,623	1,247
	843,670	31,623	42,319
Exploration and production	371,648	33,083	70,713
Construction materials and contracting	1,287,305	24,673	38,602
Construction services	774,103	7,011	36,733
Other	1,254	5,516	1,862
	2,434,310	70,283	147,910
Intersegment eliminations	—	(101,906)	(3,259)

Total	$ 3,277,980	$ —	$ 186,970

Nine Months Ended September 30, 2012	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$ 174,410	$ —	$ 22,977
Natural gas distribution	504,805	—	10,314
Pipeline and energy services	105,184	36,393	21,884
	784,399	36,393	55,175
Exploration and production	289,106	25,114	(56,860)
Construction materials and contracting	1,229,731	11,756	24,748
Construction services	688,368	1,078	29,951
Other	2,684	4,303	6,705
	2,209,889	42,251	4,544
Intersegment eliminations	—	(78,644)	—
Total	$ 2,994,288	$ —	$ 59,719

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 18 - Employee benefit plans

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

Three Months Ended September 30,	Pension Benefits 2013	2012	Other Postretirement Benefits 2013	2012
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$ 39	$ 349	$ 419	$ 437
Interest cost	4,062	4,407	804	943
Expected return on assets	(4,979)	(5,865)	(1,086)	(1,222)
Amortization of prior service cost (credit)	18	(22)	(364)	(534)
Amortization of net actuarial loss	1,793	1,887	327	356
Amortization of net transition obligation	—	—	—	531
Curtailment gain	—	(1,023)	—	—
Net periodic benefit cost, including amount capitalized	933	(267)	100	511
Less amount capitalized	157	185	47	314
Net periodic benefit cost (credit)	$ 776	$ (452)	$ 53	$ 197

Nine Months Ended September 30,	Pension Benefits 2013	2012	Other Postretirement Benefits 2013	2012
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$116	$1,044	$1,257	$1,310
Interest cost	12,186	13,223	2,411	3,124
Expected return on assets	(14,937)	(17,596)	(3,258)	(3,667)
Amortization of prior service cost (credit)	54	(64)	(1,092)	(1,078)
Amortization of net actuarial loss	5,373	5,670	1,405	1,769
Amortization of net transition obligation	—	—	—	1,594
Curtailment gain	—	(1,023)	—	—
Net periodic benefit cost, including amount capitalized	2,792	1,254	723	3,052
Less amount capitalized	425	615	137	635
Net periodic benefit cost	$2,367	$639	$586	$2,417

In 2010, all benefit and service accruals for nonunion and certain union plans were frozen. In 2011 and effective September 30, 2012, all benefit and service accruals for certain additional union employees were frozen. These employees are eligible to receive additional defined contribution plan benefits.

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 and nine months ended September 30, 2013, was $1.8 million and $5.5 million, respectively. The Company's net periodic benefit cost for this plan for the three and nine months ended September 30, 2012, was $2.0 million and $6.1 million, respectively.

In 2012, the Company modified health care coverage for certain retirees. Effective January 1, 2013, post-65 coverage is replaced by a fixed-dollar subsidy for certain retirees and spouses to be used to purchase individual insurance through an exchange.

Note 19 - Regulatory matters and revenues subject to refund

On September 26, 2012, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total increase of $3.5 million annually or approximately 5.9 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. Montana-Dakota requested an interim increase, subject to refund, of $1.7 million or approximately 2.9 percent. On April 12, 2013, the MTPSC issued an interim order authorizing an interim increase of $850,000 annually to be effective with service rendered on or after April 15, 2013, subject to refund. A hearing was held August 5-6, 2013.

On December 21, 2012, Montana-Dakota filed an application with the SDPUC for a natural gas rate increase. Montana-Dakota requested a total increase of $1.5 million annually or approximately 3.3 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. On June 19, 2013, Montana-Dakota filed a notice of intent to implement an interim rate increase, subject to refund, of $1.5 million effective with service rendered on or after July 22, 2013. On October 24, 2013, Montana-Dakota and the SDPUC Staff filed a settlement stipulation, which reflects a natural gas rate increase of $900,000 annually or approximately 2.0 percent. On November 5, 2013, the SDPUC approved the settlement stipulation, with rates to be effective with service rendered on and after December 1, 2013.

On February 11, 2013, Montana-Dakota filed an application with the NDPSC for approval of an environmental cost recovery rider for recovery of Montana-Dakota's share of the costs resulting from the environmental retrofit required to be installed at the Big Stone Station. The costs proposed to be recovered are associated with the ongoing construction costs for the installation of the BART air-quality control system. On February 27, 2013, the NDPSC suspended the filing pending further review. On

May 31, 2013, Montana-Dakota filed revisions to its filing to reflect revised budget amounts. A hearing was held on September 16, 2013.

On June 14, 2013, Montana-Dakota filed for an advance determination of prudence with the NDPSC to add filterable particulate matter pollution control equipment at Montana-Dakota's Lewis & Clark generating station to comply with the Mercury and Air Toxics Standards rule, projected to be completed in 2016. Project cost is estimated to be $27.7 million. An informal hearing was held on September 25, 2013. On October 9, 2013, the NDPSC issued an order approving the advance determination of prudence.

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. Montana-Dakota requested an interim increase, subject to refund, of $4.5 million or approximately 4.2 percent. On October 9, 2013, the NDPSC approved the interim increase to be effective with service rendered on or after November 17, 2013. On October 23, 2013, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement that resolved the revenue requirement portion of the application and reflected a natural gas rate increase of $4.3 million annually or approximately 4.0 percent, and agreed that Montana-Dakota will only implement $4.3 million of interim rate relief. The NDPSC has scheduled an informal hearing on the settlement on November 13, 2013.

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. WBI Energy Transmission requested the rates to be effective December 1, 2013.

Note 20 - 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 $30.8 million, $41.6 million and $22.5 million for contingencies, including litigation, production taxes, royalty claims and environmental matters, as of September 30, 2013 and 2012, and December 31, 2012, 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. 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. We believe that it is reasonably possible that a loss related to this matter could result if LPP is successful in its appeal, the arbitration award is affirmed and LPP continues to assert its demand against Centennial under the guarantee for payment of the arbitration award, attorneys' fees and interest. For more information regarding discontinued operations, see Note 11.

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. An arbitration hearing was held in August 2010. In October 2010, the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, WBI Energy Midstream, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010. On April 20, 2011, the Colorado State District Court confirmed the arbitration award as a court judgment. WBI Energy Midstream filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals. 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. As a result of the Colorado Court of Appeals decision, in the second quarter of 2012, WBI Energy Midstream changed its estimated loss related to this matter. This resulted in a reduction of expense of $24.1 million ($15.0 million after tax), which is largely reflected in operation and maintenance expense on the Consolidated Statements of Income. On August 2, 2012, SourceGas filed a petition for writ of certiorari with the Colorado Supreme Court for review of the Colorado Court of Appeals decision which was denied on July 22, 2013. WBI Energy Midstream anticipates that 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. Expert reports submitted by Omimex contended its damages as a result of the increased operating pressures were $16.1 million to $22.6 million, however, the experts revised their calculation of Omimex's damages to $1.0 million. The parties subsequently settled the breach of contract claim and, subject to a 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.

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 $1.3 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 plans to apply for a renewal to defer the environmental remediation costs.

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. 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 $12.5 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 12, 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 and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the oil and natural gas swap and collar 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 and collar agreements at September 30, 2013, expire in the years ranging from 2013 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 $6.3 million and was reflected on the Consolidated Balance Sheet at September 30, 2013. 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 September 30, 2013, the fixed maximum amounts guaranteed under these agreements aggregated $63.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $13.0 million in 2013; $30.9 million in 2014; $1.6 million in 2015; $300,000 in 2016; $100,000 in 2017; $200,000 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 $300,000 and was reflected on the Consolidated Balance Sheet at September 30, 2013. 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 September 30, 2013, the fixed maximum amounts guaranteed under these letters of credit, aggregated $38.2 million. In 2013 and 2014, $7.7 million and $30.5 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at September 30, 2013.

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 September 30, 2013, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $900,000. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at September 30, 2013, 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 September 30, 2013.

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 September 30, 2013, approximately $552 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. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest, and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual, or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities, and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated.

The Company's evaluation of whether it qualifies as the primary beneficiary of a VIE is highly complex and involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties, and the purpose of the arrangement.

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 fifty 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. Dakota Prairie Refining entered into a term loan for project debt financing of $75 million on April 22, 2013. The 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 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:

	September 30, 2013 (In thousands)
ASSETS	
Current assets:	
Cash and cash equivalents	$23,146
Accounts receivable	1
Other current assets	25
Total current assets	23,172
Net property, plant and equipment	123,297
Total assets	$146,469
LIABILITIES	
Current liabilities:	
Accounts payable	$20,313
Long-term debt due within one year	3,000
Other accrued liabilities	363
Total current liabilities	23,676
Long-term debt	72,000
Total liabilities	$95,676

Fuel Contract On October 10, 2012, the Coyote Station entered into a new coal supply agreement with Coyote Creek which 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, of which the Company is a 25.0 percent owner, 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 September 30, 2013, 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 September 30, 2013, was $7.4 million.

Note 21 - Subsequent events

On October 1, 2013, MDU Energy Capital entered into a $30.0 million credit agreement with a maturity date of March 30, 2014.

Cascade entered into a note purchase agreement on October 30, 2013, and issued $50.0 million of Senior Notes with due dates ranging from August 2025 to August 2028 at a weighted average interest rate of 4.24 percent.

Intermountain entered into a note purchase agreement on October 30, 2013, and issued $50.0 million of Senior Notes with due dates ranging from October 2025 to October 2028 at a weighted average interest rate of 4.21 percent.

On November 1, 2013, Centennial issued $25.0 million of Senior Notes under a note purchase agreement dated June 27, 2013, with due dates ranging from November 2023 to November 2028 at a weighted average interest rate of 4.84 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 17.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities 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, 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 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 2012 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Dollars in millions, where applicable)			
Electric	$11.4	$11.0	$25.7	$23.0
Natural gas distribution	(11.2)	(8.8)	15.4	10.3
Pipeline and energy services	5.3	3.3	1.3	21.9
Exploration and production	17.4	(87.8)	70.7	(56.9)
Construction materials and contracting	49.2	41.9	38.6	24.7
Construction services	12.2	9.9	36.7	30.0
Other	1.3	.8	2.1	1.9
Intersegment eliminations	(1.2)	—	(3.3)	—
Earnings (loss) before discontinued operations	84.4	(29.7)	187.2	54.9
Income (loss) from discontinued operations, net of tax	(.1)	(.1)	(.2)	4.8
Earnings (loss) on common stock	$84.3	$(29.8)	$187.0	$59.7
Earnings (loss) per common share – basic:				
Earnings (loss) before discontinued operations	$.45	$(.16)	$.99	$.29
Discontinued operations, net of tax	—	—	—	.03
Earnings (loss) per common share – basic	$.45	$(.16)	$.99	$.32
Earnings (loss) per common share – diluted:				
Earnings (loss) before discontinued operations	$.44	$(.16)	$.99	$.29
Discontinued operations, net of tax	—	—	—	.03
Earnings (loss) per common share – diluted	$.44	$(.16)	$.99	$.32

Three Months Ended September 30, 2013 and 2012 Consolidated earnings for the quarter ended September 30, 2013, increased $114.1 million from the comparable prior period largely due to:

- Absence of the write-down of oil and natural gas properties of $100.9 million (after tax), as discussed in Note 5, increased oil production and higher average realized oil prices, partially offset by a loss of $10.5 million (after tax) resulting from a realized commodity derivative loss in 2013 compared to a realized commodity derivative gain in 2012, unrealized commodity derivative loss of $7.9 million (after tax) in 2013 compared to $700,000 (after tax) in 2012, as well as higher depreciation, depletion and amortization expense at the exploration and production business
- Higher aggregate, asphalt and other product line margins at the construction materials and contracting business

Nine Months Ended September 30, 2013 and 2012 Consolidated earnings for the nine months ended September 30, 2013, increased $127.3 million from the comparable prior period largely due to:

- Absence of the write-down of oil and natural gas properties of $100.9 million (after tax), as discussed in Note 5, increased oil production and higher average realized natural gas and oil prices, partially offset by a loss of $16.1 million (after tax) resulting from a realized commodity derivative loss in 2013 compared to a realized commodity derivative gain in 2012, higher depreciation, depletion and amortization expense, decreased natural gas production, as well as higher production taxes at the exploration and production business
- Higher asphalt, aggregate and other product line margins at the construction materials and contracting business
- Higher equipment sales and rental margins, as well as higher workloads and margins in the Western and Central regions, partially offset by higher selling, general and administrative costs at the construction services business
-

Increased retail sales volumes and a gain on the sale of a nonregulated appliance service and repair business, partially offset by higher depreciation, depletion and amortization expense at the natural gas distribution business

Partially offsetting these increases were:

- Absence of a 2012 net benefit related to the natural gas gathering operations litigation of $15.0 million (after tax), as discussed in Note 20, as well as an impairment of coalbed natural gas gathering assets of $9.0 million (after tax) in 2013 compared to an impairment of $1.7 million (after tax) in 2012, at the pipeline and energy services business
- Loss from discontinued operations of $200,000 (after tax) compared to income from discontinued operations of $4.8 million (after tax) in 2012, as discussed in Note 11

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

Electric

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Dollars in millions, where applicable)			
Operating revenues	$68.3	$63.5	$189.9	$174.4
Operating expenses:				
Fuel and purchased power	20.0	17.6	59.8	51.2
Operation and maintenance	19.5	17.9	56.4	53.1
Depreciation, depletion and amortization	8.1	8.1	24.6	24.2
Taxes, other than income	2.7	2.6	8.4	7.9
	50.3	46.2	149.2	136.4
Operating income	18.0	17.3	40.7	38.0
Earnings	$11.4	$11.0	$25.7	$23.0
Retail sales (million kWh)	795.2	753.8	2,329.4	2,189.8
Sales for resale (million kWh)	5.4	8.9	21.5	11.8
Average cost of fuel and purchased power per kWh	$.024	$.022	$.024	$.022

Three Months Ended September 30, 2013 and 2012 Electric earnings increased $400,000 (4 percent) due to higher retail sales margins, largely the result of increased retail sales volumes of 5 percent, primarily to large commercial and industrial customers. Largely offsetting this increase was higher operation and maintenance expense of $1.0 million (after tax), largely higher payroll-related costs.

Nine Months Ended September 30, 2013 and 2012 Electric earnings increased $2.7 million (12 percent) due to higher retail sales margins, largely the result of increased retail sales volumes of 6 percent, primarily to residential, small and large commercial and industrial customers due to increased customer growth, as well as weather variances from last year. Largely offsetting this increase was higher operation and maintenance expense, which includes $1.6 million (after tax) largely related to higher payroll-related costs and increased contract services, offset in part by lower benefit-related costs.

Natural Gas Distribution

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Dollars in millions, where applicable)			
Operating revenues	$77.5	$80.1	$536.8	$504.8
Operating expenses:				
Purchased natural gas sold	36.5	38.0	323.5	300.2
Operation and maintenance	35.1	31.8	104.9	102.9
Depreciation, depletion and amortization	12.7	11.4	37.3	34.0
Taxes, other than income	7.3	7.0	32.9	33.2
	91.6	88.2	498.6	470.3
Operating income (loss)	(14.1)	(8.1)	38.2	34.5
Earnings (loss)	$(11.2)	$(8.8)	$15.4	$10.3
Volumes (MMdk):				
Sales	7.6	8.0	67.7	60.1
Transportation	37.0	30.0	105.6	94.7
Total throughput	44.6	38.0	173.3	154.8
Degree days (% of normal)*				
Montana-Dakota/Great Plains	34%	38%	101%	75%
Cascade	74%	91%	92%	98%
Intermountain	89%	51%	109%	92%
Average cost of natural gas, including transportation, per dk	$4.84	$4.73	$4.78	$4.99

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

Three Months Ended September 30, 2013 and 2012 The natural gas distribution business recognized a seasonal loss of $11.2 million compared to a seasonal loss of $8.8 million a year ago (28 percent decrease). The decline was the result of:

- Higher operation and maintenance expense, which includes $1.8 million (after tax) largely related to higher payroll-related and benefit-related costs
- Higher depreciation, depletion and amortization expense of $800,000 (after tax), primarily resulting from higher property, plant and equipment balances
- Lower margins, which includes $900,000 (after tax) largely related to retail sales and the absence of nonregulated service and repair margins due to the sale of Montana-Dakota's nonregulated appliance service and repair business in March 2013

Partially offsetting these decreases were:

- Lower net interest expense, which includes $800,000 (after tax) largely related to lower average interest rates
- A favorable resolution of a state income tax matter of $1.0 million (after tax)

Nine Months Ended September 30, 2013 and 2012 Earnings at the natural gas distribution business increased $5.1 million (49 percent) due to:

- Increased retail sales volumes of 13 percent, largely resulting from colder weather than last year, partially offset by weather normalization adjustments in certain jurisdictions

- A $2.8 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business
- Lower net interest expense, which includes $1.9 million (after tax) largely related to lower average interest rates
- A favorable resolution of a state income tax matter of $1.0 million (after tax)

Partially offsetting these increases were:

- Increased depreciation, depletion and amortization expense of $2.0 million (after tax), as previously discussed
- Higher operation and maintenance expense, which includes $1.7 million (after tax) largely related to higher payroll-related costs, offset in part by lower benefit-related costs
- Lower other income, which includes $900,000 (after tax) largely lower allowance for funds used during construction

- Absence of nonregulated service and repair margins due to the sale of Montana-Dakota's nonregulated appliance service and repair business in March 2013

Pipeline and Energy Services

	Three Months Ended September 30,		Nine Months Ended September 30,			
	2013	2012	2013		2012	
	(Dollars in millions)					
Operating revenues	$51.3	$48.3	$148.6		$141.6	
Operating expenses:						
Purchased natural gas sold	14.0	10.8	42.6		35.4	
Operation and maintenance	16.1	19.2	65.3	*	34.8	**
Depreciation, depletion and amortization	7.1	7.3	22.0		20.4	
Taxes, other than income	3.3	3.5	10.3		10.5	
	40.5	40.8	140.2		101.1	
Operating income	10.8	7.5	8.4		40.5	
Earnings	$5.3	$3.3	$1.3	*	$21.9	**
Transportation volumes (MMdk)	52.1	34.1	129.2		103.0	
Natural gas gathering volumes (MMdk)	10.6	10.7	30.5		36.5	
Customer natural gas storage balance (MMdk):						
Beginning of period	25.2	40.4	43.7		36.0	
Net injection (withdrawal)	12.9	8.8	(5.6	)	13.2	
End of period	38.1	49.2	38.1		49.2	

* Reflects an impairment of coalbed natural gas gathering assets of $14.5 million ($9.0 million after tax).
** Reflects a net benefit of $24.1 million ($15.0 million after tax) related to the natural gas gathering operations litigation, largely reflected in operation and maintenance expense, as discussed in Note 20, as well as an impairment of coalbed natural gas gathering assets of $2.7 million ($1.7 million after tax).

Three Months Ended September 30, 2013 and 2012 Pipeline and energy services earnings increased $2.0 million (62 percent) due to:

- Lower operation and maintenance expense, which includes $1.6 million (after tax) largely related to lower payroll-related costs, contract services and legal
- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, primarily due to higher volumes
- Higher earnings of $600,000 (after tax) due to increased transportation volumes

These increases were partially offset by lower storage services revenue of $1.4 million (after tax), largely due to lower average rates and lower average storage balances.

Nine Months Ended September 30, 2013 and 2012 Pipeline and energy services earnings decreased $20.6 million (94 percent) due to:

- Absence of the 2012 net benefit of $15.0 million (after tax) related to the natural gas gathering operations litigation, as discussed in Note 20
- An impairment of coalbed natural gas gathering assets of $9.0 million (after tax) in 2013, compared to an impairment of $1.7 million (after tax) in 2012, largely resulting from low natural gas prices, as discussed in Note 6
-

- Lower earnings of $2.5 million (after tax) resulting from lower natural gas gathering volumes from existing operations, largely resulting from customers experiencing production curtailments, normal declines and deferral of natural gas development activity
- Lower storage services revenue of $2.3 million (after tax), largely due to lower average rates

These decreases were partially offset by:

- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, as previously discussed

- Lower operation and maintenance expense (excluding the asset impairments, net benefit related to the natural gas gathering operations litigation and Pronghorn-related expense), which includes $2.6 million (after tax), as previously discussed
- Lower depreciation, depletion and amortization expense of $1.0 million (after tax) (excluding depreciation on Pronghorn oil and natural gas gathering and processing assets)

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Dollars in millions, where applicable)			
Operating revenues:				
Oil	$121.4	$75.1	$327.3	$217.4
NGL	7.6	7.9	21.3	24.6
Natural gas	20.1	16.7	62.5	48.1
Realized gain (loss) on commodity derivatives	(6.6)	10.0	(1.0)	24.6
Unrealized loss on commodity derivatives	(12.6)	(1.2)	(5.4)	(.5)
	129.9	108.5	404.7	314.2
Operating expenses:				
Operation and maintenance:				
Lease operating costs	20.6	20.7	63.4	58.2
Gathering and transportation	3.5	4.3	12.1	12.8
Other	12.5	9.6	32.9	28.4
Depreciation, depletion and amortization	49.6	41.4	137.8	112.6
Taxes, other than income:				
Production and property taxes	13.3	9.6	37.1	27.8
Other	.2	.2	.9	.8
Write-down of oil and natural gas properties	—	160.1	—	160.1
	99.7	245.9	284.2	400.7
Operating income (loss)	30.2	(137.4)	120.5	(86.5)
Earnings (loss)	$17.4	$(87.8)	$70.7	$(56.9)
Production:				
Oil (MBbls)	1,252	912	3,571	2,555
NGL (MBbls)	196	211	588	610
Natural gas (MMcf)	7,302	7,390	21,002	25,676
Total production (MBOE)	2,664	2,354	7,659	7,444
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):				
Oil (per Bbl)	$97.00	$82.37	$91.64	$85.09
NGL (per Bbl)	$39.02	$37.32	$36.24	$40.32
Natural gas (per Mcf)	$2.75	$2.25	$2.98	$1.88
Average realized prices (including realized gain/loss on commodity derivatives):				
Oil (per Bbl)	$91.03	$85.61	$91.13	$85.69
NGL (per Bbl)	$39.02	$37.32	$36.24	$40.32

Natural gas (per Mcf)	$2.87	$3.20	$3.02	$2.77
Average depreciation, depletion and amortization rate, per BOE	$17.90	$16.85	$17.25	$14.44
Production costs, including taxes, per BOE:				
Lease operating costs	$7.74	$8.77	$8.28	$7.81
Gathering and transportation	1.33	1.84	1.58	1.72
Production and property taxes	4.98	4.07	4.85	3.74
	$14.05	$14.68	$14.71	$13.27

Three Months Ended September 30, 2013 and 2012 Exploration and production earnings increased $105.2 million due to:

- Absence of the write-down of oil and natural gas properties of $100.9 million (after tax), as discussed in Note 5
- Increased oil production of 37 percent, primarily related to drilling activity in the Bakken area, as well as the Paradox Basin
- Higher average realized oil prices of 18 percent, excluding gain/loss on commodity derivatives
- Higher average realized natural gas prices of 22 percent, excluding gain/loss on commodity derivatives

Partially offsetting these increases were:

- A loss of $10.5 million (after tax) resulting from a realized commodity derivative loss in 2013 compared to a realized commodity derivative gain in 2012
- Unrealized commodity derivative loss of $7.9 million (after tax) in 2013 compared to $700,000 (after tax) in 2012
- Higher depreciation, depletion and amortization expense of $5.1 million (after tax), largely due to increased oil production
- Higher production taxes of $2.3 million (after tax), primarily resulting from higher revenues
- Higher general and administrative expense of $1.8 million (after tax)
- Higher interest expense of $800,000 (after tax), primarily due to higher effective interest rates and lower capitalized interest, offset in part by lower average borrowings

Nine Months Ended September 30, 2013 and 2012 Exploration and production earnings increased $127.6 million due to:

- Absence of the write-down of oil and natural gas properties of $100.9 million (after tax), as discussed in Note 5
- Increased oil production of 40 percent, primarily related to drilling activity in the Bakken area, as well as the Paradox Basin
- Higher average realized natural gas prices of 59 percent, excluding gain/loss on commodity derivatives
- Higher average realized oil prices of 8 percent, excluding gain/loss on commodity derivatives

Partially offsetting these increases were:

- A loss of $16.1 million (after tax) resulting from a realized commodity derivative loss in 2013 compared to a realized commodity derivative gain in 2012, as previously discussed
- Higher depreciation, depletion and amortization expense of $15.9 million (after tax), largely due to higher depletion rates
- Decreased natural gas production of 18 percent, largely related to production curtailments, normal declines and deferral of certain natural gas development activity
- Higher production taxes of $5.8 million (after tax), as previously discussed
- Increased lease operating expenses of $3.3 million (after tax), largely related to higher costs in the Bakken area resulting from increased production volumes and higher workover costs, as well as higher costs in the Paradox Basin resulting from increased production volumes, partially offset by lower costs at certain natural gas properties where curtailments of production have occurred
- Unrealized commodity derivative loss of $3.4 million (after tax) in 2013 compared to $300,000 (after tax) in 2012
- Higher net interest expense of $3.0 million (after tax), primarily due to lower capitalized interest and higher average borrowings
- Higher general and administrative expense of $2.9 million (after tax)
- Lower average realized NGL prices of 10 percent

Construction Materials and Contracting

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Dollars in millions)			
Operating revenues	$714.4	$650.0	$1,312.0	$1,241.5
Operating expenses:				
Operation and maintenance	600.9	549.6	1,148.8	1,103.3
Depreciation, depletion and amortization	19.0	20.3	56.7	59.9
Taxes, other than income	11.6	11.0	30.7	29.6
	631.5	580.9	1,236.2	1,192.8
Operating income	82.9	69.1	75.8	48.7
Earnings	$49.2	$41.9	$38.6	$24.7
Sales (000's):				
Aggregates (tons)	9,902	9,009	19,012	17,983
Asphalt (tons)	3,311	3,013	4,978	4,874
Ready-mixed concrete (cubic yards)	1,132	1,105	2,458	2,410

Three Months Ended September 30, 2013 and 2012 Earnings at the construction materials and contracting business increased $7.3 million (17 percent) due to:

- Higher earnings of $3.3 million (after tax) resulting from higher aggregate margins and volumes
- Higher earnings of $3.1 million (after tax) resulting from higher asphalt margins and volumes
- Higher earnings resulting from higher other product line margins

Partially offsetting these increases was higher selling, general and administrative costs of $700,000 (after tax), largely payroll-related.

Nine Months Ended September 30, 2013 and 2012 Earnings at the construction materials and contracting business increased $13.9 million (56 percent) due to:

- Higher earnings of $5.9 million (after tax) resulting from higher asphalt margins
- Higher earnings of $3.3 million (after tax) resulting from higher aggregate margins and volumes
- Increased construction workloads and margins of $1.8 million (after tax)
- Higher earnings of $1.4 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Higher earnings resulting from higher other product line margins
- Lower selling, general and administrative costs of $600,000 (after tax), largely insurance costs

Partially offsetting these increases was higher interest expense of $1.1 million (after tax), resulting from higher average interest rates, as well as higher average borrowings.

Construction Services

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In millions)			
Operating revenues	$270.1	$247.2	$781.1	$689.4

Operating expenses:				
Operation and maintenance	238.8	219.9	683.2	606.5
Depreciation, depletion and amortization	3.0	2.8	8.9	8.3
Taxes, other than income	7.3	7.2	25.3	22.1
	249.1	229.9	717.4	636.9
Operating income	21.0	17.3	63.7	52.5
Earnings	$12.2	$9.9	$36.7	$30.0

Three Months Ended September 30, 2013 and 2012 Construction services earnings increased $2.3 million (23 percent), primarily due to higher equipment sales and rental margins, as well higher workloads and margins in the Central and Western regions.

Nine Months Ended September 30, 2013 and 2012 Construction services earnings increased $6.7 million (23 percent) primarily due to higher equipment sales and rental margins, as well as higher workloads and margins in the Western and Central regions. These increases were partially offset by higher selling, general and administrative costs of $1.9 million (after tax).

Other

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In millions)			
Operating revenues	$2.3	$2.3	$6.8	$7.0
Operating expenses:				
Operation and maintenance	(1.4	)1.5	1.2	4.4
Depreciation, depletion and amortization	.5	.5	1.5	1.5
Taxes, other than income	.1	—	.2	.1
	(.8	)2.0	2.9	6.0
Operating income	3.1	.3	3.9	1.0
Income from continuing operations	1.3	.8	2.1	1.9
Income (loss) from discontinued operations, net of tax	(.1	)(.1	)(.2	)4.8
Earnings	$1.2	$.7	$1.9	$6.7

Three Months Ended September 30, 2013 and 2012 Other earnings increased $500,000, primarily due to lower insurance costs, partially offset by lower earnings from equity method investments.

Nine Months Ended September 30, 2013 and 2012 Other earnings decreased $4.8 million, primarily due to a loss from discontinued operations of $200,000 (after tax) in 2013 compared to income from discontinued operations of $4.8 million (after tax) in 2012. This decrease is largely related to the absence of a net benefit in 2012, as discussed in Note 11.

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In millions)			
Intersegment transactions:				
Operating revenues	$28.0	$26.4	$101.9	$78.6
Purchased natural gas sold	14.7	13.6	60.8	56.5
Operation and maintenance	11.3	12.8	35.7	22.1
Income taxes	.8	—	2.1	—
Earnings on common stock	1.2	—	3.3	—

For more information on intersegment eliminations, see Note 17.

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 2012 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 2013, diluted, are projected in the range of $1.35 to $1.45, an increase from prior guidance of $1.30 to $1.40, excluding discontinued operations, the unrealized loss of $3.4 million (after tax) on commodity derivatives and the natural gas gathering asset impairment of $9.0 million (after tax). Including these adjustments, 2013 GAAP earnings guidance is in the range of $1.30 to $1.40 per share. 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 and strategic acquisitions.
- The Company focuses on creating value through vertical integration between its business units. For example, the pipeline and energy services business' partially owned Dakota Prairie Refinery under construction in the Bakken region will have the construction materials and services business involved in constructing the facility, the exploration and production business supplying production, either directly or in kind, to the plant, the pipeline transporting natural gas to the plant, and the utility supplying electricity.

Electric and natural gas distribution

- The Company filed an application September 18, 2013, with the NDPSC for a natural gas rate increase, as discussed in Note 19.
- The Company filed an application June 14, 2013, for an advance determination of prudence with NDPSC to add pollution control equipment at the Lewis & Clark generating station, as discussed in Note 19.
- The Company filed an application February 11, 2013, with 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, as discussed in Note 19.
- The Company filed an application December 21, 2012, with the SDPUC for a natural gas rate increase, as discussed in Note 19.

- The Company filed an application September 26, 2012, with the MTPSC for a natural gas rate increase, as discussed in Note 19.

- The Company is constructing an 88-MW simple-cycle natural gas turbine and associated facilities, with an estimated project cost of $77 million and a projected in-service date in third quarter 2014. It is located on owned property adjacent to the Company's Heskett Generating Station near Mandan, North Dakota. The capacity is necessary to meet the requirements of the Company's integrated electric system customers and will be a partial replacement for third-party contract capacity expiring in 2015. Advance determination of prudence and a Certificate of Public Convenience and Necessity have been received from the NDPSC.
- Investments are being made in 2013 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.
- Rate base growth is projected to be approximately 6 percent compounded annually over the next five years, including plans for an approximate $1 billion capital investment program.

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- 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 engaged on a 30-mile, $62 million, natural gas line project into the Hanford Nuclear Site in Washington.
- The Company along with a partner expects to build a 345kv transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, about 160 miles, at a total cost of approximately $360 million. The Company's share would be one-half. The project is a Midwest Independent Transmission System Operator 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. The project is expected to be complete in 2019.
- 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. Total project costs are estimated to be approximately $300 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 May 2012, the Company purchased a 50 percent undivided interest in Whiting Oil and Gas Corporation's Pronghorn natural gas and oil midstream assets near Belfield, North Dakota, in the Bakken area. The Company invested approximately $100 million in 2012 including the purchase price. The Belfield natural gas processing plant has an inlet processing capacity of 35 MMcf per day. The Company will receive a full year of benefit from this acquisition in 2013.
- The Company is engaged in various natural gas pipeline projects to be constructed in 2014. Namely 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 $53 million.
- In May 2013, the Company announced plans for a proposed 400-mile natural gas pipeline from western North Dakota to western Minnesota to transport natural gas to markets in eastern North Dakota, Minnesota and Wisconsin. The Company is evaluating alternate routes that would terminate further north, providing customers with access to additional markets via interconnections with Great Lakes Gas Transmission, TransCanada and Viking Gas Transmission in northwest Minnesota. The pipeline initially 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 $650 million to $700 million. Following an open season and receipt of adequate capacity commitments and necessary permits and regulatory approvals, construction on the new pipeline would begin as early as 2016.
- On October 31, 2013, WBI Energy Transmission filed a Section 4 rate case with the FERC, as discussed in Note 19.
- 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 $400 million in capital expenditures in 2013. The 2013 planned capital expenditure total does not include potential acquisitions nor proceeds from closed divestitures of non-strategic assets of approximately $30 million.
- For 2013, the Company expects a 30 to 35 percent increase in oil production. Noting the level of production reported for the fourth quarter 2012 (59 percent higher than fourth quarter 2011), the company anticipates fourth quarter 2013 production growth of 10 to 15 percent over last year.
- The Company expects a slight decrease in NGL production and a 15 to 20 percent decrease in natural gas production for 2013 compared to a year ago. The vast majority of the capital program is focused on growing oil production considering current relative commodity prices. The Company expects to return to some natural gas development when

the commodity prices make it more profitable to do so.

- During the third quarter 2013, the Company had a total of four drilling rigs deployed on its acreage in the Bakken, Paradox and Texas areas.
- Bakken areas
The Company owns a total of approximately 127,000 net acres of leaseholds in Mountrail, Stark and Richland counties.
Capital expenditures are expected to total approximately $210 million in 2013. Two rigs are in operation.
Net oil production for third quarter 2013 was approximately 8,300 BOPD.
- Paradox Basin, Utah
The Company has approximately 92,000 net acres and also has an option to earn another 20,000 acres.
Capital expenditures are expected to total $80 million in 2013. The Company is operating one rig in the area and expects to add a second rig within the next two to three months.
Following nine months of flowing at a constant 1,500 BOPD gross, the CCU 12-1 well came off its plateau rate and is still flowing at approximately 1,000 BOPD.
Net oil production for third quarter 2013 was approximately 2,300 BOPD, up 272 percent from third quarter 2012 and consistent with second quarter 2013. Well down time, delayed completion activity, and the CCU 12-1 coming off of plateau limited growth in the third quarter 2013. Current production is approximately 3,000 BOPD.
The latest well completed was the CCU 36-1, which has been flowing consistently above 1,250 BOPD since October 11, 2013, with a flowing pressure of approximately 3,400 psi.
The Company's understanding of this play and the quality of the play continues to improve. Accelerated development of the play will be largely dependent upon receiving sufficient permits to sustain a multi-rig program. It is anticipated that this field will play a key role in the Company's oil growth strategy.
- Texas
The Company is targeting areas that have the potential for higher liquids content with approximately $40 million of capital planned for this year.
- Other opportunities
The remaining forecasted 2013 capital has been allocated to other operated and non-operated opportunities.
- Earnings guidance reflects estimated average NYMEX index prices for November and December 2013 in the range of $95 to $105 per Bbl of crude oil, and $3.50 to $4.00 per Mcf of natural gas. Estimated prices for NGL are in the range of $35 to $50 per Bbl.
- For the last three months of 2013, the Company has derivative instruments for 11,000 BOPD utilizing swaps and costless collars with a weighted average price of $97.76 and $92.50/$107.03 (floor/ceiling) respectively, and 60,000 MMBtu of natural gas per day utilizing swaps at a weighted average price of $3.80.
- For the first six months of 2014, the Company has derivative instruments for 11,000 BOPD, and 5,000 BOPD for July through December 2014, utilizing swaps with a weighted average price of $94.74, and for 2014 the Company has derivative instruments for 20,000 MMBtu of natural gas per day utilizing swaps at a weighted average price of $4.13.
- For 2015, the Company has a derivative instrument for 10,000 MMBtu of natural gas per day utilizing a swap at $4.2825.
- The commodity derivative instruments that are in place as of October 31, 2013, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (Bbl/MMBtu)	Price (Per Bbl/MMBtu)
Crude Oil	Collar	NYMEX	10/13 - 12/13	92,000	$95.00-$117.00
Crude Oil	Collar	NYMEX	10/13 - 12/13	92,000	$90.00-$97.05
Crude Oil	Swap	NYMEX	10/13 - 12/13	46,000	$95.00
Crude Oil	Swap	NYMEX	10/13 - 12/13	46,000	$95.30
Crude Oil	Swap	NYMEX	10/13 - 12/13	46,000	$100.00
Crude Oil	Swap	NYMEX	10/13 - 12/13	46,000	$100.02
Crude Oil	Swap	NYMEX	10/13 - 12/13	92,000	$102.00
Crude Oil	Swap	NYMEX	10/13 - 12/13	92,000	$104.00
Crude Oil	Swap	NYMEX	10/13 - 12/13	92,000	$98.00
Crude Oil	Swap	NYMEX	10/13 - 12/13	46,000	$94.15
Crude Oil	Swap	NYMEX	10/13 - 12/13	46,000	$94.00
Crude Oil	Swap	NYMEX	10/13 - 12/13	92,000	$97.45
Crude Oil	Swap	NYMEX	10/13 - 12/13	92,000	$94.15
Crude Oil	Swap	NYMEX	10/13 - 12/13	92,000	$95.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$95.15
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$95.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$90.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$91.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$92.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$93.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$98.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$99.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$100.07
Crude Oil	Swap	NYMEX	1/14 - 12/14	365,000	$94.05
Crude Oil	Swap	NYMEX	1/14 - 12/14	365,000	$95.00
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
Natural Gas	Swap	NYMEX	10/13 - 12/13	920,000	$3.76
Natural Gas	Swap	NYMEX	10/13 - 12/13	920,000	$3.90
Natural Gas	Swap	NYMEX	10/13 - 12/13	920,000	$4.00
Natural Gas	Swap	NYMEX	10/13 - 12/13	1,840,000	$3.50
Natural Gas	Swap	NYMEX	10/13 - 12/14	4,570,000	$4.13
Natural Gas	Swap	NYMEX	1/14 - 12/14	3,650,000	$4.13
Natural Gas	Swap	NYMEX	1/15 - 12/15	3,650,000	$4.2825

Construction materials and contracting

- Approximate work backlog as of September 30, 2013, was $525 million, compared to $464 million a year ago. Private work represents 13 percent of construction backlog and public work represents 87 percent of backlog. The backlog includes a variety of projects such as highway paving projects, airports, bridge work, reclamation and harbor expansions.
- The Company's approximate backlog in North Dakota as of September 30, 2013, was $156 million, including a $55 million North Dakota highway construction contract, the largest contract in the Company's history. North Dakota backlog was $64 million a year ago.
- Projected revenues included in the Company's 2013 earnings guidance are in the range of $1.6 billion to $1.7 billion.

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- The Company anticipates margins in 2013 to be higher than 2012.
- 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.

Construction services

- Approximate work backlog as of September 30, 2013, was $433 million, compared to $370 million a year ago. 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 September 30, 2013, was $1 million, unchanged from the prior year.
- Projected revenues included in the Company's 2013 earnings guidance are in the range of $1.0 billion to $1.1 billion.
- The Company anticipates higher workloads and comparable margins in 2013 compared to 2012.
- 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.

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Note 9, which is incorporated by reference.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

The Company's critical accounting policies involving significant estimates include impairment testing of 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 2012 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2012 Annual Report.

LIQUIDITY AND CAPITAL COMMITMENTS

At September 30, 2013, the Company had cash and cash equivalents of $66.2 million and available capacity of $345.8 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 nine months of 2013 increased $99.6 million from the comparable period in 2012. Excluding the effect of the write-down of oil and natural gas properties in 2012, the increase was largely due to lower working capital requirements of $82.9 million, primarily at the exploration and production business.

Investing activities Cash flows used in investing activities in the first nine months of 2013 decreased $47.0 million from the comparable period in 2012. The decrease was primarily due to lower acquisition-related capital expenditures, primarily at the pipeline and energy services business. Partially offsetting the decrease in cash flows used in investing activities was higher ongoing capital expenditures of $18.7 million, largely related to Dakota Prairie Refinery at the pipeline and energy services segment and electric generation projects at the electric business, partially offset by lower capital expenditures at the exploration and production segment.

Financing activities Cash flows provided by financing activities in the first nine months of 2013 decreased $40.9 million from the comparable period in 2012, primarily due to higher repayment of long-term debt of $182.5 million. Partially offsetting the decrease in cash flows provided by financing activities were higher issuance of long-term debt of $96.9 million; lower dividends paid of $29.7 million resulting from the Company accelerating the payment date for the quarterly common stock dividend from January 1, 2013 to December 31, 2012; as well as a cash contribution of $13.0 million related to noncontrolling interest.

Defined benefit pension plans

There were no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2012 Annual Report. For more information, see Note 18 and Part II, Item 7 in the 2012 Annual Report.

Capital expenditures

Net capital expenditures for the first nine months of 2013 were $588.6 million and are estimated to be approximately $820 million for 2013. 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 2013 capital expenditures referred to previously. The Company expects the 2013 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 September 30, 2013. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For additional information on the covenants, certain other conditions and cross-default provisions, see Part II, Item 8 - Note 9, in the 2012 Annual Report.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at September 30, 2013:

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		$44.5	(b)	$—		10/4/17
Cascade Natural Gas Corporation	Revolving credit agreement		$50.0	(c)	$7.0		$2.2	(d)	7/9/18
Intermountain Gas Company	Revolving credit agreement		$65.0	(e)	$48.5		$—		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement	(f)	$500.0		$292.0	(b)	$—		6/8/17

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letter of credit, as discussed in Note 20, reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90 million.
(f) The $500 million commercial paper program is supported by a revolving credit agreement with various banks totaling $500 million (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 2.5 times for the 12 months ended September 30, 2013, including the after-tax noncash write-down of oil and natural gas properties of $145.9 million in the fourth quarter of 2012. If the $145.9 million after-tax noncash write-down was excluded, the coverage of fixed charges including preferred stock dividends would have been 4.7 times for the 12 months ended September 30, 2013.

Due to the after-tax noncash write-downs of oil and natural gas properties in 2012, earnings were insufficient by $51.2 million to cover fixed charges for the 12 months ended December 31, 2012. If the $246.8 million after-tax noncash write-downs were excluded, the coverage of fixed charges including preferred stock dividends would have been 4.4 times for the 12 months ended December 31, 2012.

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 meet 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, 61 percent and 60 percent at September 30, 2013 and 2012 and December 31, 2012, 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 a Sales Agency Financing 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 are expected to be used for corporate development purposes and other general corporate purposes. The Company has not issued any stock under the Sales Agency Financing Agreement through September 30, 2013.

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.

Cascade Natural Gas Corporation On July 9, 2013, Cascade entered into a revolving credit agreement which replaces the existing revolving credit agreement and extends the termination date to July 9, 2018. The credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the revolving credit agreement.

Intermountain Gas Company On July 15, 2013, Intermountain entered into a revolving credit agreement which replaces the existing revolving credit agreement and extends the termination date to July 13, 2018. The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Intermountain's credit agreement also contains cross-default provisions. These provisions state that if Intermountain fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, or certain conditions result in an early termination date under any swap contract that is in excess of a specified amount, then Intermountain will be in default under the revolving credit agreement.

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.

WBI Energy Transmission, Inc. On September 12, 2013, WBI Energy Transmission entered into a $175 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 September 30, 2013, which reduced capacity under this uncommitted private shelf agreement. This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

Off balance sheet arrangements

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

Centennial continues to guarantee CEM's obligations under a construction contract for an electric generating facility near Hobbs, New Mexico. For more information, see Note 20.

Contractual obligations and commercial commitments

There are no material changes in the Company's contractual obligations relating to estimated interest payments, operating leases, derivatives, asset retirement obligations and minimum funding requirements for its defined benefit plans for 2013 from those reported in the 2012 Annual Report.

The Company's contractual obligations relating to long-term debt at September 30, 2013, increased $266.9 million or 15 percent from December 31, 2012. As of September 30, 2013, the Company's contractual obligations related to long-term debt aggregated $2,011.9 million. The scheduled amounts of redemption (for the twelve months ended September 30, of each year listed) aggregate $44.0 million in 2014; $224.6 million in 2015; $362.7 million in 2016; $393.0 million in 2017; $220.6 million in 2018; and $767.0 million thereafter.

The Company's contractual obligations relating to purchase commitments at September 30, 2013, increased $256.1 million or 13 percent from December 31, 2012. As of September 30, 2013, the Company's contractual obligations related to purchase commitments aggregated $2,182.6 million. The scheduled amounts of redemption (for the twelve months ended September 30, of each year listed) aggregate $700.2 million in 2014; $286.6 million in 2015; $160.2 million in 2016; $89.1 million in 2017; $67.9 million in 2018; and $878.6 million thereafter.

For more information on the Company's uncertain tax positions, see Note 16.

For more information on contractual obligations and commercial commitments, see Part II, Item 7 in the 2012 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 2012 Annual Report, the Consolidated Statements of Comprehensive Income and Note 14.

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 and basis differentials on forecasted sales of oil and natural gas production.

The following table summarizes derivative agreements entered into by Fidelity as of September 30, 2013. 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 2013	$97.76	828	$(3,149)
Oil swap agreements maturing in 2014	$94.74	2,911	$(4,077)
Natural gas swap agreements maturing in 2013	$3.80	5,520	$1,116
Natural gas swap agreements maturing in 2014	$4.13	7,300	$1,971
Natural gas swap agreement maturing in 2015	$4.28	3,650	$824

	Weighted Average Floor/Ceiling Price (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Oil collar agreements maturing in 2013	$92.50/$107.03	184	$(430)

Interest rate risk

There were no material changes to interest rate risk faced by the Company from those reported in the 2012 Annual Report.

At September 30, 2013, 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 2012 Annual Report.

At September 30, 2013, 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 September 30, 2013, 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 20, 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 2012 Annual Report other than the risk associated with the regulatory approval, permitting, construction, startup and/or operation of power generation facilities and Dakota Prairie Refinery; the risk related to environmental laws and regulations; and the risk associated with company operations that could be adversely impacted by global climate change initiatives to reduce GHG emissions. These factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Economic Risks
The regulatory approval, permitting, construction, startup and/or operation of power generation facilities and Dakota Prairie Refinery may involve unanticipated events or delays that could negatively impact the Company's business and its results of operations and cash flows.

The construction, startup and operation of power generation facilities and Dakota Prairie Refinery involve many risks, which may include: delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to complete financing; inability to negotiate acceptable equipment acquisition, construction, fuel and crude oil supply, off-take, transmission, transportation or other material agreements; changes in markets and market prices for power, crude oil and refined products; cost increases; as well as the risk of performance below expected levels of output or efficiency. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

Environmental 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. 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, as well as 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, 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 rule 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 is required to control non-mercury metal emissions at the Lewis & Clark Station near Sidney, Montana. On October 9, 2013, Montana-Dakota received an order from the NDPSC approving Montana-Dakota's request for advance determination of prudence to install a baghouse at Lewis & Clark Station. Controls must be installed by April 16, 2015, or April 16, 2016, if a one-year extension is granted for installation.

Hydraulic fracturing is an important common practice used by Fidelity that involves injecting water; sand; guar, a water thickening agent; 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 only affect 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.

Initiatives to reduce GHG emissions could adversely impact the Company's operations.

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. On June 25, 2013, President Obama released his Climate Action Plan for the U.S. in which he states his goal to reduce GHG emissions "in the range of 17 percent" below 2005 levels by 2020. The president issued a memorandum to the EPA on the same day, instructing the EPA to re-propose the GHG NSPS rule for new electric generation units. The EPA released the re-proposed rule on September 20, 2013, which takes the place of the rule proposed in 2012 for new electric generation units that the EPA did not finalize. This rule applies to new fossil fuel-fired electric generation units, including coal-fired units, natural gas-fired combined-cycle units and natural gas-fired simple cycle peaking units. The EPA's 1,100 pound of carbon dioxide per megawatt hour emissions standard for coal-fired units does not allow for any new coal-fired electric generation to be constructed unless carbon dioxide is captured and sequestered. At this time, the EPA is not proposing standards of performance for modified or reconstructed sources, therefore no impacts to Montana-Dakota's existing electric generating facilities are expected.

The president also directed the EPA to develop a GHG NSPS standard for existing fossil fuel-fired electric generation units by June 1, 2014, with finalization by June 1, 2015. The president did not specify a GHG standard or the format of the standard.

The primary GHG emitted from the Company's operations is carbon dioxide from combustion of fossil fuels at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 70 percent of Montana-Dakota's owned generating capacity and more than 90 percent of the electricity it generates is from coal-fired facilities. Montana-Dakota also owns approximately 100 MW of natural gas- and oil-fired peaking plants.

Montana-Dakota's existing electric generating facilities are expected to be subject to GHG laws or regulations within the next few years through a GHG NSPS for existing and modified units. Implementation of treaties, legislation or regulations to reduce GHG emissions could affect Montana-Dakota's electric utility operations by requiring expanded energy conservation efforts or increased development of renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs. If Montana-Dakota does not receive timely and full recovery of GHG emission compliance costs from its customers, then such costs could have an adverse impact on the results of its operations.

In addition to Montana-Dakota's electric generation operations, the GHG emissions from the Company's other operations are monitored, analyzed and reported as required in accordance with applicable laws and regulations. The Company monitors the development of GHG regulations and the potential for GHG regulations to impact all existing and future operations.

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

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: November 7, 2013	BY:	/s/ Doran N. Schwartz Doran N. Schwartz Vice President and Chief Financial Officer
	BY:	/s/ Nicole A. Kivisto Nicole A. Kivisto Vice President, Controller and Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.

+10(a)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of September 30, 2013
+10(b)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013
+10(c)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013
+10(d)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 23, 2013
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 September 30, 2013, 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.