MDU RESOURCES GROUP INC
Form 10-Q
August 08, 2014

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

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

For The Quarterly Period Ended June 30, 2014

OR

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

For the Transition Period from _____________ to ______________

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

Delaware (State or other jurisdiction of incorporation or organization)	41-0423660 (I.R.S. Employer Identification No.)

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

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

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

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

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

Large accelerated filer ý Accelerated filer o

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of August 1, 2014: 193,946,489 shares.

DEFINITIONS

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

Abbreviation or Acronym	
2013 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2013
ASC	FASB Accounting Standards Codification
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
California Superior Court	Superior Court of the State of California, County of Los Angeles (South District - Long Beach)
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
Connolly-Pacific	Connolly-Pacific Co., an indirect wholly owned subsidiary of Knife River
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant being built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (2.5 percent ownership interest at June 30, 2014, 2.5, 2.5, 2.5 and 14.99 percent ownership interests were sold in the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010, respectively)
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)

EPA	U.S. Environmental Protection Agency
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital

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

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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 18.

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PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and pipeline and energy services	$254,689	$227,442	$746,231	$651,565
Exploration and production, construction materials and contracting, construction services and other	839,357	833,153	1,390,668	1,340,633
Total operating revenues	1,094,046	1,060,595	2,136,899	1,992,198
Operating expenses:				
Fuel and purchased power	21,046	18,169	47,590	39,777
Purchased natural gas sold	84,415	70,255	329,307	269,442
Operation and maintenance:				
Electric, natural gas distribution and pipeline and energy services	61,764	76,627	129,047	142,730
Exploration and production, construction materials and contracting, construction services and other	675,330	661,495	1,121,282	1,055,511
Depreciation, depletion and amortization	103,126	95,289	202,683	188,850
Taxes, other than income	49,431	47,382	105,152	99,979
Total operating expenses	995,112	969,217	1,935,061	1,796,289
Operating income	98,934	91,378	201,838	195,909
Loss from equity method investments	(297)	(7)	(245)	(319)
Other income	2,777	1,436	4,908	2,677
Interest expense	21,516	21,427	42,487	42,300
Income before income taxes	79,898	71,380	164,014	155,967
Income taxes	27,118	24,988	55,050	52,983
Income from continuing operations	52,780	46,392	108,964	102,984
Income (loss) from discontinued operations, net of tax (Note 11)	547	(59)	502	(136)
Net income	53,327	46,333	109,466	102,848
Net loss attributable to noncontrolling interest	(779)	(179)	(1,302)	(179)
Dividends declared on preferred stocks	171	171	342	342
Earnings on common stock	$53,935	$46,341	$110,426	$102,685
Earnings per common share - basic:				
Earnings before discontinued operations	$.28	$.25	$.58	$.54
Discontinued operations, net of tax	—	—	—	—
Earnings per common share - basic	$.28	$.25	$.58	$.54
Earnings per common share - diluted:				
Earnings before discontinued operations	$.28	$.24	$.58	$.54

Discontinued operations, net of tax	—	—	—	—
Earnings per common share - diluted	$ .28	$ .24	$ .58	$ .54
Dividends declared per common share	$ .1775	$ .1725	$ .3550	$ .3450
Weighted average common shares outstanding - basic	192,060	188,831	190,946	188,831
Weighted average common shares outstanding - diluted	192,659	189,463	191,543	189,460

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Net income	$53,327	$46,333	$109,466	$102,848
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 $52 for the three months ended and $0 and $(3,116) for the six months ended in 2014 and 2013, respectively	—	254	—	(5,594)
Reclassification adjustment for (gain) loss on derivative instruments included in net income, net of tax of $10 and $(322) for the three months ended and $213 and $(1,948) for the six months ended in 2014 and 2013, respectively	13	(395)	357	(3,168)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	13	(141)	357	(8,762)
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $150 and $543 for the three months ended and $318 and $862 for the six months ended in 2014 and 2013, respectively	245	424	520	1,072
Foreign currency translation adjustment recognized during the period, net of tax of $26 and $(234) for the three months ended and $54 and $(197) for the six months ended in 2014 and 2013, respectively	42	(390)	88	(302)
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 $4 and $(77) for the three months ended and $5 and $(100) for the six months ended in 2014 and 2013, respectively	8	(142)	10	(187)
Reclassification adjustment for loss on available-for-sale investments included in net income, net of tax of $17 and $23 for the three months ended and $17 and $42 for the six months ended in 2014 and 2013, respectively	32	43	32	79
Net unrealized gain (loss) on available-for-sale investments	40	(99)	42	(108)
Other comprehensive income (loss)	340	(206)	1,007	(8,100)
Comprehensive income	53,667	46,127	110,473	94,748
Comprehensive loss attributable to noncontrolling interest	(779)	(179)	(1,302)	(179)
Comprehensive income attributable to common stockholders	$54,446	$46,306	$111,775	$94,927

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

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

	June 30, 2014	June 30, 2013	December 31, 2013
(In thousands, except shares and per share amounts)			
ASSETS			
Current assets:			
Cash and cash equivalents	$90,318	$114,971	$45,225
Receivables, net	731,247	734,765	713,067
Inventories	331,422	345,885	282,391
Deferred income taxes	29,110	27,959	25,048
Commodity derivative instruments	129	9,797	1,447
Prepayments and other current assets	93,980	58,870	49,510
Total current assets	1,276,206	1,292,247	1,116,688
Investments	116,594	106,508	112,939
Property, plant and equipment	9,390,538	8,454,204	8,803,866
Less accumulated depreciation, depletion and amortization	4,011,858	3,709,679	3,872,487
Net property, plant and equipment	5,378,680	4,744,525	4,931,379
Deferred charges and other assets:			
Goodwill	636,039	636,039	636,039
Other intangible assets, net	11,266	15,312	13,099
Other	249,532	297,040	251,188
Total deferred charges and other assets	896,837	948,391	900,326
Total assets	$7,668,317	$7,091,671	$7,061,332
LIABILITIES AND EQUITY			
Current liabilities:			
Short-term borrowings	$—	$31,600	$11,500
Long-term debt due within one year	42,215	69,091	12,277
Accounts payable	424,201	411,621	404,961
Taxes payable	48,985	89,896	74,175
Dividends payable	34,388	32,745	33,737
Accrued compensation	50,024	44,159	69,661
Commodity derivative instruments	17,449	1,388	7,483
Other accrued liabilities	179,402	185,389	171,106
Total current liabilities	796,664	865,889	784,900
Long-term debt	2,144,879	1,937,663	1,842,286
Deferred credits and other liabilities:			
Deferred income taxes	925,813	782,838	859,306
Other liabilities	736,519	810,639	718,938
Total deferred credits and other liabilities	1,662,332	1,593,477	1,578,244
Commitments and contingencies			
Equity:			
Preferred stocks	15,000	15,000	15,000
Common stockholders' equity:			
Common stock			
Authorized - 500,000,000 shares, $1.00 par value			
Shares issued - 194,138,654 at June 30, 2014,	194,139	189,369	189,869

189,369,450 at June 30, 2013 and 189,868,780 at December 31, 2013			
Other paid-in capital	1,186,900	1,040,379	1,056,996
Retained earnings	1,645,291	1,494,419	1,603,130
Accumulated other comprehensive loss	(37,198)	(56,821)	(38,205)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,985,506	2,663,720	2,808,164
Total stockholders' equity	3,000,506	2,678,720	2,823,164
Noncontrolling interest	63,936	15,922	32,738
Total equity	3,064,442	2,694,642	2,855,902
Total liabilities and equity	$7,668,317	$7,091,671	$7,061,332

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

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

	Six Months Ended June 30,	
	2014	2013
	(In thousands)	
Operating activities:		
Net income	$109,466	$102,848
Income (loss) from discontinued operations, net of tax	502	(136)
Income from continuing operations	108,964	102,984
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	202,683	188,850
Loss, net of distributions, from equity method investments	245	1,491
Deferred income taxes	60,141	19,790
Unrealized (gain) loss on commodity derivatives	11,908	(7,215)
Excess tax benefit on stock-based compensation	(4,729)	—
Changes in current assets and liabilities, net of acquisitions:		
Receivables	(8,501)	(65,637)
Inventories	(48,857)	(29,923)
Other current assets	(37,460)	(18,044)
Accounts payable	(23,277)	18,940
Other current liabilities	(36,447)	23,071
Other noncurrent changes	(13,638)	(741)
Net cash provided by continuing operations	211,032	233,566
Net cash provided by (used in) discontinued operations	(491)	360
Net cash provided by operating activities	210,541	233,926
Investing activities:		
Capital expenditures	(390,126)	(431,439)
Acquisitions, net of cash acquired	(206,304)	—
Net proceeds from sale or disposition of property and other	11,917	20,884
Investments	(1,208)	16
Net cash used in continuing operations	(585,721)	(410,539)
Net cash provided by discontinued operations	—	—
Net cash used in investing activities	(585,721)	(410,539)
Financing activities:		
Issuance of short-term borrowings	—	29,600
Repayment of short-term borrowings	(11,500)	—
Issuance of long-term debt	441,447	450,461
Repayment of long-term debt	(111,539)	(214,473)
Proceeds from issuance of common stock	132,268	—
Dividends paid	(67,717)	(32,915)
Excess tax benefit on stock-based compensation	4,729	—
Contribution from noncontrolling interest	32,500	10,000
Net cash provided by continuing operations	420,188	242,673
Net cash provided by discontinued operations	—	—

Net cash provided by financing activities	420,188	242,673
Effect of exchange rate changes on cash and cash equivalents	85	(131)
Increase in cash and cash equivalents	45,093	65,929
Cash and cash equivalents -- beginning of year	45,225	49,042
Cash and cash equivalents -- end of period	$90,318	$114,971

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

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MDU RESOURCES GROUP, INC.
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

June 30, 2014 and 2013
(Unaudited)

Note 1 - Basis of presentation
The accompanying consolidated interim financial statements were prepared in conformity with the basis of presentation reflected in the consolidated financial statements included in the Company's 2013 Annual Report, and the standards of accounting measurement set forth in the interim reporting guidance in the ASC and any amendments thereto adopted by the FASB. Interim financial statements do not include all disclosures provided in annual financial statements and, accordingly, these financial statements should be read in conjunction with those appearing in the 2013 Annual Report. The information is unaudited but includes all adjustments that are, in the opinion of management, necessary for a fair presentation of the accompanying consolidated interim financial statements and are of a normal recurring nature. Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses. Management has also evaluated the impact of events occurring after June 30, 2014, up to the date of issuance of these consolidated interim financial statements.

Note 2 - Seasonality of operations
Some of the Company's operations are highly seasonal and revenues from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Accordingly, the interim results for particular businesses, and for the Company as a whole, may not be indicative of results for the full fiscal year.

Note 3 - Accounts receivable and allowance for doubtful accounts
Accounts receivable consist primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $29.6 million, $35.1 million and $36.4 million at June 30, 2014 and 2013, and December 31, 2013, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts at June 30, 2014 and 2013, and December 31, 2013, was $9.6 million, $10.6 million and $10.1 million, respectively.

Note 4 - Inventories and natural gas in storage
Inventories, other than natural gas in storage for the Company's regulated operations, are stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year is included in inventories. Inventories consisted of:

	June 30, 2014	June 30, 2013	December 31, 2013
	(In thousands)		
Aggregates held for resale	$112,129	$103,503	$101,568
Asphalt oil	76,525	91,837	38,099
Materials and supplies	70,938	74,648	69,808
Merchandise for resale	25,507	27,330	21,720
Natural gas in storage (current)	10,903	14,287	16,417

Other	35,420	34,280	34,779
Total	$331,422	$345,885	$282,391

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, is included in other assets and was $47.4 million, $48.6 million and $48.3 million at June 30, 2014 and 2013, and December 31, 2013, respectively.

Note 5 - Impairment of long-lived assets

During the second quarter of 2013, the Company recognized an impairment of coalbed natural gas gathering assets at the pipeline and energy services segment of $14.5 million ($9.0 million after tax), which is recorded in operation and maintenance expense on the Consolidated Statements of Income. The impairment is 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 6 - 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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Weighted average common shares outstanding - basic	192,060	188,831	190,946	188,831
Effect of dilutive performance share awards	599	632	597	629
Weighted average common shares outstanding - diluted	192,659	189,463	191,543	189,460
Shares excluded from the calculation of diluted earnings per share	—	—	—	—

Note 7 - Cash flow information

Cash expenditures for interest and income taxes were as follows:

	Six Months Ended June 30,	
	2014	2013
	(In thousands)	
Interest, net of amount capitalized	$39,441	$41,440
Income taxes paid (refunded), net	$39,984	$(2,649)

Noncash investing transactions were as follows:

	June 30,	
	2014	2013
	(In thousands)	
Property, plant and equipment additions in accounts payable	$95,833	$77,073

Note 8 - New Accounting Standard

Revenue from Contracts with Customers In May 2014, the FASB issued guidance on accounting for revenue from contracts with customers. The guidance provides for a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry specific guidance. This guidance will be effective for the Company on January 1, 2017. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption. In addition, the modified approach will require additional disclosures. The Company is evaluating the effects the adoption of the new revenue guidance will have on its results of operations, financial position, cash flows and disclosures, as well as its method of adoption.

Note 9 - Comprehensive income (loss)
The after-tax changes in the components of accumulated other comprehensive loss were as follows:

Three Months Ended June 30, 2014	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges (In thousands)	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
Balance at beginning of period	$(3,421)	$(33,532)	$(621)	$ 36	$(37,538)
Other comprehensive income (loss) before reclassifications	—	—	42	8	50
Amounts reclassified from accumulated other comprehensive loss	13	245	—	32	290
Net current-period other comprehensive income	13	245	42	40	340
Balance at end of period	$(3,408)	$(33,287)	$(579)	$ 76	$(37,198)

Three Months Ended June 30, 2013	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges (In thousands)	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
Balance at beginning of period	$(2,603)	$(53,699)	$(423)	$ 110	$(56,615)
Other comprehensive income (loss) before reclassifications	254	—	(390)	(142)	(278)
Amounts reclassified from accumulated other comprehensive loss	(395)	424	—	43	72
Net current-period other comprehensive income (loss)	(141)	424	(390)	(99)	(206)
Balance at end of period	$(2,744)	$(53,275)	$(813)	$ 11	$(56,821)

Six Months Ended June 30, 2014	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges (In thousands)	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
Balance at beginning of period	$(3,765)	$(33,807)	$(667)	$ 34	$(38,205)
Other comprehensive income (loss) before reclassifications	—	—	88	10	98
Amounts reclassified from accumulated other	357	520	—	32	909

comprehensive loss					
Net current-period other comprehensive income	357	520	88	42	1,007
Balance at end of period	$(3,408)	$(33,287)	$(579)	$ 76	$(37,198)

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Six Months Ended June 30, 2013	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges (In thousands)	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
Balance at beginning of period	$6,018	$(54,347)	$(511)	$ 119	$(48,721)
Other comprehensive income (loss) before reclassifications	(5,594)	—	(302)	(187)	(6,083)
Amounts reclassified from accumulated other comprehensive loss	(3,168)	1,072	—	79	(2,017)
Net current-period other comprehensive income (loss)	(8,762)	1,072	(302)	(108)	(8,100)
Balance at end of period	$(2,744)	$(53,275)	$(813)	$ 11	$(56,821)

Reclassifications out of accumulated other comprehensive loss were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,		Location on Consolidated Statements of Income
	2014	2013	2014	2013	
	(In thousands)				
Reclassification adjustment for gain (loss) on derivative instruments included in net income:					
Commodity derivative instruments	$137	$1,381	$(250)	$5,896	Operating revenues
Interest rate derivative instruments	(160)	(664)	(320)	(780)	Interest expense
	(23)	717	(570)	5,116	
	10	(322)	213	(1,948)	Income taxes
	(13)	395	(357)	3,168	
Amortization of postretirement liability losses included in net periodic benefit cost	(395)	(967)	(838)	(1,934)	(a)
	150	543	318	862	Income taxes
	(245)	(424)	(520)	(1,072)	
Reclassification adjustment for loss on available-for-sale investments included in net income	(49)	(66)	(49)	(121)	Other income
	17	23	17	42	Income taxes
	(32)	(43)	(32)	(79)	
Total reclassifications	$(290)	$(72)	$(909)	$2,017	

(a) Included in net periodic benefit cost (credit). For more information, see Note 19.

Note 10 - Acquisition

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

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

Note 11 - Discontinued operations

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources 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 had a benefit related to the resolution of this matter in the second quarter of 2014, which are reflected in discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For more information, see Note 21.

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 June 30, 2014, the Company had no significant equity method investments.

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

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

At June 30, 2013, the equity method investments had total assets of $114.8 million and long-term debt of $56.2 million. The Company's investment in its equity method investments was approximately $5.5 million, including undistributed earnings of $2.0 million, at June 30, 2013.

Note 13 - Goodwill and other intangible assets
The changes in the carrying amount of goodwill were as follows:

Six Months Ended June 30, 2014	Balance as of January 1, 2014*	Goodwill Acquired During the Year	Balance as of June 30, 2014*
	(In thousands)		
Natural gas distribution	$345,736	$—	$345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	104,276	—	104,276
Total	$636,039	$—	$636,039

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

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

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

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

Other amortizable intangible assets were as follows:

	June 30, 2014	June 30, 2013	December 31, 2013
	(In thousands)		
Customer relationships	$21,310	$21,310	$21,310
Accumulated amortization	(14,734)	(12,715)	(13,726)
	6,576	8,595	7,584
Noncompete agreements	5,080	6,186	6,186
Accumulated amortization	(3,936)	(4,557)	(4,840)
	1,144	1,629	1,346
Other	10,921	10,979	10,995
Accumulated amortization	(7,375)	(5,891)	(6,826)
	3,546	5,088	4,169
Total	$11,266	$15,312	$13,099

Amortization expense for amortizable intangible assets for the three and six months ended June 30, 2014, was $1.0 million and $1.8 million, respectively. Amortization expense for amortizable intangible assets for the three and six months ended June 30, 2013, was $1.0 million and $1.8 million, respectively. Estimated amortization expense for amortizable intangible assets is $3.3 million in 2014, $2.5 million in 2015, $2.2 million in 2016, $1.9 million in 2017, $1.0 million in 2018 and $2.2 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 June 30, 2014, the Company had no outstanding foreign currency or interest rate hedges.

The fair value of derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability.

Fidelity

At June 30, 2014 and 2013, and December 31, 2013, Fidelity held oil swap and collar agreements with total forward notional volumes of 2.5 million, 3.1 million and 2.9 million Bbl, respectively, and natural gas swap agreements with total forward notional volumes of 11.0 million, 21.4 million and 18.3 million MMBtu, respectively. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas on its forecasted sales of oil and natural gas production.

Effective April 1, 2013, Fidelity elected to de-designate all commodity derivative contracts previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively for all of its commodity derivative instruments. When the criteria for hedge accounting is not met or when hedge accounting is not elected, realized gains and losses and unrealized gains and losses are both recorded in operating revenues on the Consolidated Statements of Income. As a result of discontinuing hedge accounting on commodity derivative instruments, gains and losses on the oil and natural gas derivative instruments remain in accumulated other comprehensive income (loss) as of the de-designation date and are reclassified into earnings in future periods as the underlying hedged transactions affect earnings. At April 1, 2013, accumulated other comprehensive income (loss) included $1.8 million of unrealized gains, representing the mark-to-market value of the Company's commodity derivative instruments that qualified as cash flow hedges as of the balance sheet date. The Company expects to reclassify into earnings from accumulated other comprehensive income (loss) the remaining value related to de-designating commodity derivative instruments over the next 6 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.

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.

Certain of Fidelity's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of 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 June 30, 2014 and 2013, and December 31, 2013, were $17.4 million, $1.4 million and $7.5 million, respectively. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on June 30, 2014 and 2013, and December 31, 2013, were $17.4 million, $1.4 million and $7.5 million, respectively.

Centennial
Centennial has historically entered into interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. As of June 30, 2014 and 2013, and December 31, 2013, Centennial had no outstanding interest rate swap agreements.

Fidelity and Centennial
The gains and losses on derivative instruments were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Commodity derivatives designated as cash flow hedges:				
Amount of loss recognized in accumulated other comprehensive loss (effective portion), net of tax	$—	$—	$—	$(6,154)
Amount of (gain) loss reclassified from accumulated other comprehensive loss into operating revenues (effective portion), net of tax	(86)	(871)	158	(3,714)
Amount of loss recognized in operating revenues (ineffective portion), before tax	—	—	—	(1,422)
Interest rate derivatives designated as cash flow hedges:				
Amount of gain recognized in accumulated other comprehensive loss (effective portion), net of tax	—	254	—	560
	99	475	199	546

Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax				
Amount of loss recognized in interest expense (ineffective portion), before tax	—	(610)	—	(769)
Commodity derivatives not designated as hedging instruments:				
Amount of gain (loss) recognized in operating revenues, before tax	(5,196)	13,047	(11,908)	8,637

Over the next 12 months net losses of approximately $535,000 (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, as the hedged transactions affect earnings.

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 June 30, 2014	Fair Value at June 30, 2013	Fair Value at December 31, 2013
		(In thousands)		
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$129	$9,797	$1,447
	Other assets - noncurrent	131	1,447	503
Total asset derivatives		$260	$11,244	$1,950

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at June 30, 2014	Fair Value at June 30, 2013	Fair Value at December 31, 2013
		(In thousands)		
Not designated as hedges:				
Commodity derivatives	Commodity derivative instruments	$17,449	$1,388	$7,483
Total liability derivatives		$17,449	$1,388	$7,483

All of the Company's commodity derivative instruments at June 30, 2014 and 2013, and December 31, 2013, were subject to legally enforceable master netting agreements. However, the Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. The gross derivative assets and liabilities (excluding settlement receivables and payables that may be subject to the same master netting agreements) presented on the Consolidated Balance Sheets and the amount eligible for offset under the master netting agreements is presented in the following table:

June 30, 2014	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$260	$(260)	$—
Total assets	$260	$(260)	$—
Liabilities:			
Commodity derivatives	$17,449	$(260)	$17,189
Total liabilities	$17,449	$(260)	$17,189

June 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	$11,244	$(1,388)	$9,856
Total assets	$11,244	$(1,388)	$9,856
Liabilities:			
Commodity derivatives	$1,388	$(1,388)	$—

Total liabilities	$ 1,388	$ (1,388	) $ —

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

Note 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 $64.4 million, $54.0 million and $62.4 million, at June 30, 2014 and 2013, and December 31, 2013, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments were $1.1 million and $2.0 million for the three and six months ended June 30, 2014, respectively. The net unrealized gains on these investments were $700,000 and $5.1 million for the three and six months ended June 30, 2013, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its available-for-sale securities, which include mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. Unrealized gains or losses are recorded in accumulated other comprehensive income (loss). Details of available-for-sale securities were as follows:

June 30, 2014	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$ 7,989	$ 91	$ (5	) $ 8,075
U.S. Treasury securities	2,066	30	—	2,096
Total	$ 10,055	$ 121	$ (5	) $ 10,171

June 30, 2013	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$ 8,035	$ 58	$ (41	) $ 8,052
U.S. Treasury securities	1,920	15	(15	) 1,920
Total	$ 9,955	$ 73	$ (56	) $ 9,972

December 31, 2013	Cost	Gross Unrealized	Gross Unrealized	Fair Value

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

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

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs.

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

The Company's Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 mortgage-backed securities and U.S. Treasury securities are based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources.

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

The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is also evaluated.

The estimated fair value of the Company's Level 2 interest rate derivative instruments is measured using quoted market prices or pricing models using prevailing market interest rates as of the measurement date. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is also evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the six months ended June 30, 2014 and 2013, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at June 30, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at June 30, 2014
	(In thousands)			
Assets:				
Money market funds	$—	$19,990	$—	$19,990
Insurance contract*	—	64,449	—	64,449
Available-for-sale securities:				
Mortgage-backed securities	—	8,075	—	8,075
U.S. Treasury securities	—	2,096	—	2,096
Commodity derivative instruments	—	260	—	260
Total assets measured at fair value	$—	$94,870	$—	$94,870
Liabilities:				

Commodity derivative instruments	$—	$17,449	$—	$17,449
Total liabilities measured at fair value	$—	$17,449	$—	$17,449

* The insurance contract invests approximately 21 percent in common stock of mid-cap companies, 18 percent in common stock of small-cap companies, 29 percent in common stock of large-cap companies, 31 percent in fixed-income investments and 1 percent in cash equivalents.

	Fair Value Measurements at June 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 June 30, 2013
	(In thousands)			
Assets:				
Money market funds	$—	$29,902	$—	$29,902
Insurance contract*	—	54,039	—	54,039
Available-for-sale securities:				
Mortgage-backed securities	—	8,052	—	8,052
U.S. Treasury securities	—	1,920	—	1,920
Commodity derivative instruments	—	11,244	—	11,244
Total assets measured at fair value	$—	$105,157	$—	$105,157
Liabilities:				
Commodity derivative instruments	$—	$1,388	$—	$1,388
Total liabilities measured at fair value	$—	$1,388	$—	$1,388

* The insurance contract invests approximately 28 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 16 percent in fixed-income investments.

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
	(In thousands)			
Assets:				
Money market funds	$—	$19,227	$—	$19,227
Insurance contract*	—	62,370	—	62,370
Available-for-sale securities:				
Mortgage-backed securities	—	8,193	—	8,193
U.S. Treasury securities	—	1,917	—	1,917
Commodity derivative instruments	—	1,950	—	1,950
Total assets measured at fair value	$—	$93,657	$—	$93,657
Liabilities:				
Commodity derivative instruments	$—	$7,483	$—	$7,483
Total liabilities measured at fair value	$—	$7,483	$—	$7,483

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

The Company 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 quarter of 2013, 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, 2013, 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 June 30, 2014	$2,187,094	$2,283,351
Long-term debt at June 30, 2013	$2,006,754	$2,090,208
Long-term debt at December 31, 2013	$1,854,563	$1,912,590

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

Note 16 - Long-term debt

On May 8, 2014, the Company amended its revolving credit agreement to increase the borrowing limit to $175.0 million and extend the termination date to May 8, 2019.

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

On May 8, 2014, Centennial entered into an amended and restated revolving credit agreement which increased the borrowing limit to $650.0 million and extended the termination date to May 8, 2019. The credit agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on subsidiary indebtedness and the making of certain loans and investments.

Centennial's revolving credit agreement contains cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial 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, then Centennial will be in default under the revolving credit agreement.

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

In addition, borrowings outstanding that were classified as long-term debt under the Company’s and Centennial’s commercial paper programs totaled $268.0 million at June 30, 2014, compared to $153.9 million at December 31, 2013, respectively.

Note 17 - Equity

A summary of the changes in equity was as follows:

Six Months Ended June 30, 2014	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
	(In thousands)		
Balance at December 31, 2013	$2,823,164	$32,738	$2,855,902
Net income (loss)	110,768	(1,302)	109,466
Other comprehensive income	1,007	—	1,007
Dividends declared on preferred stocks	(342)	—	(342)
Dividends declared on common stock	(68,025)	—	(68,025)
Stock-based compensation	2,796	—	2,796
Issuance of common stock upon vesting of performance shares, net of shares used for tax withholdings	(5,564)	—	(5,564)
Net tax benefit on stock-based compensation	4,729	—	4,729
Issuance of common stock	131,973	—	131,973
Contribution from noncontrolling interest	—	32,500	32,500
Balance at June 30, 2014	$3,000,506	$63,936	$3,064,442

Six Months Ended June 30, 2013	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
	(In thousands)		
Balance at December 31, 2012	$2,648,248	$—	$2,648,248
Net income (loss)	103,027	(179)	102,848
Other comprehensive loss	(8,100)	—	(8,100)
Dividends declared on preferred stocks	(342)	—	(342)
Dividends declared on common stock	(65,147)	—	(65,147)
Stock-based compensation	2,453	—	2,453
Net tax deficit on stock-based compensation	(1,419)	—	(1,419)
Contribution from noncontrolling interest	—	16,101	16,101
Balance at June 30, 2013	$2,678,720	$15,922	$2,694,642

Note 18 - 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 the Dakota Prairie Refinery in conjunction with Calumet to refine crude oil and also provides cathodic protection and other energy-related services.

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

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

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

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

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

Three Months Ended June 30, 2014	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$65,149	$—	$7,823
Natural gas distribution	146,077	—	(4,494)
Pipeline and energy services	43,463	7,888	5,789
	254,689	7,888	9,118
Exploration and production	129,309	10,271	19,180
Construction materials and contracting	434,452	8,106	10,554
Construction services	275,109	7,273	14,307
Other	487	1,744	1,608
	839,357	27,394	45,649
Intersegment eliminations	—	(35,282)	(832)
Total	$1,094,046	$—	$53,935

Three Months Ended June 30, 2013	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$56,981	$—	$4,410
Natural gas distribution	127,584	—	(5,893)
Pipeline and energy services	42,877	7,999	(6,395)
	227,442	7,999	(7,878)
Exploration and production	137,053	12,556	32,995
Construction materials and contracting	418,345	12,958	10,025
Construction services	277,259	2,340	12,915
Other	496	1,839	340
	833,153	29,693	56,275
Intersegment eliminations	—	(37,692)	(2,056)
Total	$1,060,595	$—	$46,341

Six Months Ended June 30, 2014	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$ 138,796	$ —	$ 18,856
Natural gas distribution	520,311	—	22,768
Pipeline and energy services	87,124	26,164	10,138
	746,231	26,164	51,762
Exploration and production	245,976	31,139	40,120
Construction materials and contracting	598,875	12,123	(13,019)
Construction services	545,002	11,010	30,875
Other	815	3,468	1,872
	1,390,668	57,740	59,848
Intersegment eliminations	—	(83,904)	(1,184)
Total	$ 2,136,899	$ —	$ 110,426

Six Months Ended June 30, 2013	External Operating Revenues	Inter-segment Operating Revenues	Earnings on Common Stock
	(In thousands)		
Electric	$ 121,635	$ —	$ 14,235
Natural gas distribution	459,337	—	26,624
Pipeline and energy services	70,593	26,717	(4,064)
	651,565	26,717	36,795
Exploration and production	252,415	22,369	53,279
Construction materials and contracting	580,323	17,251	(10,557)
Construction services	507,065	3,914	24,579
Other	830	3,657	645
	1,340,633	47,191	67,946
Intersegment eliminations	—	(73,908)	(2,056)
Total	$ 1,992,198	$ —	$ 102,685

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 19 - Employee benefit plans

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

Three Months Ended June 30,	Pension Benefits 2014	2013	Other Postretirement Benefits 2014	2013
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$31	$37	$380	$334
Interest cost	4,405	4,106	924	667
Expected return on assets	(5,484)	(4,875)	(1,242)	(1,065)
Amortization of prior service cost (credit)	18	18	(348)	(364)
Amortization of net actuarial loss	1,121	1,716	6	407
Net periodic benefit cost, including amount capitalized	91	1,002	(280)	(21)
Less amount capitalized	73	158	(19)	61
Net periodic benefit cost (credit)	$18	$844	$(261)	$(82)

Six Months Ended June 30,	Pension Benefits 2014	2013	Other Postretirement Benefits 2014	2013
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$64	$77	$759	$838
Interest cost	8,845	8,124	1,782	1,607
Expected return on assets	(10,609)	(9,958)	(2,309)	(2,172)
Amortization of prior service cost (credit)	36	36	(696)	(728)
Amortization of net actuarial loss	2,434	3,580	324	1,078
Net periodic benefit cost, including amount capitalized	770	1,859	(140)	623
Less amount capitalized	168	268	10	90
Net periodic benefit cost (credit)	$602	$1,591	$(150)	$533

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 six months ended June 30, 2014, was $1.6 million and $3.3 million, respectively. The Company's net periodic benefit cost for this plan for the three and six months ended June 30, 2013, was $1.8 million and $3.6 million, respectively.

Note 20 - Regulatory matters and revenues subject to refund

On April 8, 2014, Montana-Dakota submitted a request to the NDPSC to update the environmental cost recovery rider to reflect actual costs incurred through February 2014 and projected costs through June 2015 related to the recovery of Montana-Dakota's share of the costs resulting from the environmental retrofit required to be installed at the Big Stone Station. The NDPSC approved the proposed rider on July 10, 2014, reflecting an annual amount of $8.6 million to be recovered under the rider. The rider was effective with service rendered on and after July 15, 2014.

On September 18, 2013, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase. Montana-Dakota requested a total increase of $6.8 million annually or approximately 6.4 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, an operations building, automated meter reading and a new customer billing system. An interim increase of $4.3 million annually or approximately 4.0 percent went into effect for service rendered on or after November 17, 2013. On

December 30, 2013, the NDPSC approved a settlement agreement for an increase in the same amount as the interim increase. A hearing on the rate design portion of the case was held February 5, 2014. The NDPSC voted to approve an order approving the allocation of the revenue increase to each rate class and the rate design on April 9, 2014. Final rates were implemented May 1, 2014.

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

On October 31, 2013, WBI Energy Transmission filed a general natural gas rate change application with the FERC based on an increase in investments of $312 million, increased operating costs, and the effect of lower storage and off system volumes. On April 30, 2014, WBI Energy Transmission reached a settlement in principle with FERC Trial Staff and all active parties to resolve the rate case. WBI Energy Transmission filed settlement rates to take effect on an interim basis, effective May 1, 2014, pending final approval of the settlement. On June 4, 2014, WBI Energy Transmission submitted to the FERC an Uncontested Offer of Settlement. On June 11, 2014, the Presiding Administrative Law Judge issued a Certification of Uncontested Settlement recommending FERC approval of the settlement without modification. The matter is pending before the FERC. Based on the adjusted base period volumes filed in the case, the annual increase in revenues is approximately $11.5 million.

Note 21 - 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 $32.1 million, $32.9 million and $29.5 million for contingencies, including litigation, production taxes, royalty claims and environmental matters, at June 30, 2014 and 2013, and December 31, 2013, respectively, which include amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association seeking compensatory damages of $149.7 million. An arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award was recorded in discontinued operations on the Consolidated Statement of Income in the fourth quarter of 2011. CEM filed a petition with the New York Supreme Court to vacate the arbitration award in favor of LPP. The New York Supreme Court granted CEM's petition to vacate the arbitration award on November 20, 2012, and entered an order and judgment to that effect on June 5, 2013. LPP appealed the order and judgment and on February 20, 2014, the New York Supreme Court Appellate Division ruled the arbitration award was properly vacated. LPP filed a motion with the New York Court of Appeals for leave to appeal the decision of the New York Supreme Court Appellate Division. The motion was denied on June 10, 2014. Due to the vacation of the arbitration award, the accrual that was previously recorded in 2011 was reversed in the fourth quarter of 2012. The effect of this was recorded in discontinued operations on the Consolidated Statement of Income. For more information regarding discontinued operations, see Note 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

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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.

Former Employee Litigation On August 6, 2012, a former employee and his spouse filed actions against Connolly-Pacific and others in California Superior Court alleging the former employee contracted acute myelogenous leukemia from exposure to substances while employed as a seaman by the defendants. The plaintiffs request compensatory damages of approximately $23.8 million plus punitive damages, costs and interest. Connolly-Pacific is contesting the claims and believes it has meritorious defenses to them. Connolly-Pacific will seek insurance coverage for defense costs and any liability incurred in the litigation.

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

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

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

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

The Company also is subject to other litigation, and actual and potential claims in the ordinary course of its business which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. Accruals are based on the best information available but actual losses in future periods are affected by various factors making them uncertain. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above issues and other probable and reasonably possible losses in excess of the amounts accrued, while uncertain, will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative

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costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, Knife River - Northwest does not believe it is a Responsible Party. In addition, Knife River - Northwest has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. Knife River - Northwest has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against Knife River - Northwest and others to recover LWG's investigation costs to the extent Knife River - Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River - Northwest has agreed to participate in the alternative dispute resolution process.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above referenced administrative action.

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.7 million for remediation of this site. In January 2013, the OPUC approved Cascade's application to defer environmental remediation costs at the Eugene site for a period of 12 months starting November 30, 2012. Cascade received an order reauthorizing the deferred accounting for the 12 months starting November 30, 2013.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.6 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 agreement obligations. There is no fixed maximum amount guaranteed in relation to the oil and natural gas swap agreements as the amount of the obligation is dependent upon oil and natural gas commodity prices. The amount of derivative activity entered into by the subsidiary is limited by corporate policy. The guarantees of the oil and natural gas swap agreements at June 30, 2014, expire in the years ranging from 2014 to 2015; however, Fidelity continues to enter into additional derivative instruments and, as a result, WBI Holdings from time to time may issue additional guarantees on these derivative instruments. The amount outstanding by Fidelity was $14.5 million and was reflected on the Consolidated Balance Sheet at June 30, 2014. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At June 30, 2014, the fixed maximum amounts guaranteed under these agreements aggregated $76.7 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $21.2 million in 2014; $35.7 million in 2015; $700,000 in 2016; $600,000 in 2017; $500,000 in 2018; $500,000 in 2019; $13.5 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $200,000 and was reflected on the Consolidated Balance Sheet at June 30, 2014. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies and other agreements, some of which are guaranteed by other subsidiaries of the Company. At June 30, 2014, the fixed maximum amounts guaranteed under these letters of credit, aggregated $36.3 million. In 2014 and 2015, $7.0 million and $29.3 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at June 30, 2014.

WBI Holdings has an outstanding guarantee to WBI Energy Transmission. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At June 30, 2014, the fixed maximum amount guaranteed under this agreement was $4.0 million and is scheduled to expire in 2016. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.1 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at June 30, 2014, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at June 30, 2014.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. At June 30, 2014, approximately $666.9 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

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

Dakota Prairie Refining, LLC On February 7, 2013, WBI Energy and Calumet formed a limited liability company, Dakota Prairie Refining, and entered into an operating agreement to develop, build and operate Dakota Prairie Refinery in southwestern North Dakota. WBI Energy and Calumet each have a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of $300.0 million, under the agreement are $150.0 million and $75.0 million, respectively. Capital commitments in excess of $300.0 million are expected to be shared equally between WBI Energy and Calumet. The total project cost is currently estimated at $350 million. Dakota Prairie Refining entered into a term loan for project debt financing of $75.0 million on April 22, 2013. The operating agreement provides for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt will be allocated to Calumet. Calumet's future cash distributions from Dakota Prairie Refining will be decreased by the principal and interest to be paid on the project debt, while the cash distributions to WBI Energy will not be decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan.

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

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

	June 30, 2014	June 30, 2013	December 31, 2013
	(In thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$32,283	$63,089	$4,774
Accounts receivable	—	5	—
Other current assets	2,136	—	26
Total current assets	34,419	63,094	4,800
Net property, plant and equipment	254,079	75,216	172,073
Total assets	$288,498	$138,310	$176,873
LIABILITIES			
Current liabilities:			
Long-term debt due within one year	$3,000	$3,000	$3,000
Accounts payable	28,150	21,057	8,904

Taxes payable	225	—	5
Accrued compensation	256	—	26
Other accrued liabilities	494	300	461
Total current liabilities	32,125	24,357	12,396
Long-term debt	69,000	72,000	72,000
Total liabilities	$101,125	$96,357	$84,396

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

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

At June 30, 2014, Coyote Creek was not yet operational. The assets and liabilities of Coyote Creek and exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage, at June 30, 2014, was $9.7 million.

Note 22 - Subsequent Events

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

Fidelity entered into a purchase and sale agreement on July 17, 2014, to sell certain oil and natural gas properties in Mountrail County, North Dakota for a sale price of approximately $200.0 million, subject to accounting and purchase price adjustments customary with dispositions of this type. The effective date of the disposition is May 1, 2014, with the expected closing date to occur on or before September 30, 2014, conditioned upon the buyer completing a due diligence process, including environmental reviews, and both parties satisfying other standard closing conditions.

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 18.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide safe and reliable competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities to retain, grow and expand their customer base through extensions of existing operations, including building and upgrading electric generation and transmission and natural gas systems, and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment.

Challenges Both segments are subject to extensive regulation in the state jurisdictions where they conduct operations with respect to costs and permitted returns on investment as well as subject to certain operational, system integrity and environmental regulations. These regulations can require substantial investment to upgrade facilities. The ability of these segments to grow through acquisitions is subject to significant competition. In addition, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of any new electric generating facilities, transmission lines and other service facilities are subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will necessitate increases in electric energy prices. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas.

Pipeline and Energy Services

Strategy Utilize the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, investments in and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new energy sources for storage, gathering and transportation services; expansion of existing gathering, transmission and storage facilities; incremental expansion of pipeline capacity; expansion of midstream business to include liquid pipelines and processing/refining activities; and expansion of related energy services.

Challenges Challenges for this segment include: energy price volatility; tight 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 2013 Annual Report. For more information on each segment's key growth strategies, projections and certain assumptions, see Prospective Information. For information pertinent to various commitments and contingencies, see Notes to Consolidated Financial Statements.

Earnings Overview

The following table summarizes the contribution to consolidated earnings by each of the Company's businesses.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Dollars in millions, where applicable)			
Electric	$7.8	$4.4	$18.9	$14.2
Natural gas distribution	(4.5)	(5.9)	22.8	26.6
Pipeline and energy services	5.8	(6.4)	10.1	(4.1)
Exploration and production	19.2	33.0	40.1	53.3
Construction materials and contracting	10.6	10.0	(13.0)	(10.5)
Construction services	14.3	12.9	30.9	24.6
Other	1.1	.5	1.3	.9
Intersegment eliminations	(.9)	(2.1)	(1.2)	(2.1)
Earnings before discontinued operations	53.4	46.4	109.9	102.9
Income (loss) from discontinued operations, net of tax	.5	(.1)	.5	(.2)
Earnings on common stock	$53.9	$46.3	$110.4	$102.7
Earnings per common share – basic:				
Earnings before discontinued operations	$.28	$.25	$.58	$.54
Discontinued operations, net of tax	—	—	—	—
Earnings per common share – basic	$.28	$.25	$.58	$.54
Earnings per common share – diluted:				
Earnings before discontinued operations	$.28	$.24	$.58	$.54
Discontinued operations, net of tax	—	—	—	—
Earnings per common share – diluted	$.28	$.24	$.58	$.54

Three Months Ended June 30, 2014 and 2013 Consolidated earnings for the quarter ended June 30, 2014, increased $7.6 million (16 percent) from the comparable prior period largely due to:

- The absence of the 2013 natural gas gathering asset impairment of $9.0 million (after tax) and higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets at the pipeline and energy services business
- Higher retail sales margins at the electric business

Partially offsetting these increases were an unrealized loss on commodity derivatives of $3.3 million (after tax) in 2014 compared to an unrealized gain on commodity derivatives of $8.2 million (after tax) in 2013, a loss of $7.3 million (after tax) resulting from a realized commodity derivative loss in 2014 compared to a realized commodity derivative gain in 2013 and higher depreciation, depletion and amortization expense; partially offset by increased oil production of 14 percent and increased average realized oil prices of 6 percent, excluding gain/loss on commodity derivatives, at the exploration and production business.

Six Months Ended June 30, 2014 and 2013 Consolidated earnings for the six months ended June 30, 2014, increased $7.7 million (8 percent) from the comparable prior period largely due to:

- The absence of the 2013 natural gas gathering asset impairment of $9.0 million (after tax), as well as higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets at the pipeline and energy services business
- Higher workloads and margins in the Western region at the construction services business

Partially offsetting these increases were a loss of $14.3 million (after tax) resulting from a realized commodity derivative loss in 2014 compared to a realized commodity derivative gain in 2013, an unrealized loss on commodity derivatives of $7.5 million (after tax) in 2014 compared to an unrealized gain on commodity derivatives of $4.6 million (after tax) in 2013, higher depreciation, depletion and amortization expense, as well as decreased natural gas production of 19 percent; partially offset by higher oil production of 14 percent and higher average realized natural gas prices of 52 percent, excluding gain/loss on commodity derivatives, at the exploration and production business.

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

Electric

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Dollars in millions, where applicable)			
Operating revenues	$65.1	$57.0	$138.8	$121.6
Operating expenses:				
Fuel and purchased power	21.1	18.2	47.6	39.8
Operation and maintenance	20.5	20.5	38.9	36.8
Depreciation, depletion and amortization	8.5	7.9	17.1	16.5
Taxes, other than income	2.8	2.8	5.7	5.7
	52.9	49.4	109.3	98.8
Operating income	12.2	7.6	29.5	22.8
Earnings	$7.8	$4.4	$18.9	$14.2
Retail sales (million kWh)	721.5	691.5	1,650.4	1,534.1
Average cost of fuel and purchased power per kWh	$.027	$.024	$.027	$.024

Three Months Ended June 30, 2014 and 2013 Electric earnings increased $3.4 million (77 percent) due to:

- Higher retail sales margins, the result of higher rates, primarily due to the recovery of costs of environmental upgrades; as well as increased sales volumes of 4 percent, primarily to commercial and industrial customers
- Higher other income, which includes $800,000 (after tax) largely related to allowance for funds used during construction

Partially offsetting these increases were higher depreciation, depletion and amortization expense of $400,000 (after tax), primarily related to increased property, plant and equipment balances.

Six Months Ended June 30, 2014 and 2013 Electric earnings increased $4.7 million (32 percent) due to:

- Higher retail sales margins, the result of higher rates, primarily due to the recovery of costs of environmental upgrades; and increased sales volumes of 8 percent to all customer classes
- Higher other income, which includes $1.2 million (after tax) largely related to allowance for funds used during construction

Partially offsetting these increases were higher operation and maintenance expense, which includes $1.4 million (after tax) primarily related to higher benefit-related costs and contract services, along with higher depreciation, depletion and amortization expense of $400,000 (after tax), as previously discussed.

Natural Gas Distribution

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Dollars in millions, where applicable)			
Operating revenues	$146.1	$127.6	$520.3	$459.3
Operating expenses:				
Purchased natural gas sold	89.1	73.5	346.4	286.9
Operation and maintenance	35.9	35.7	73.8	69.9
Depreciation, depletion and amortization	13.5	12.4	26.8	24.5
Taxes, other than income	9.9	9.5	27.8	25.7
	148.4	131.1	474.8	407.0
Operating income (loss)	(2.3)	(3.5)	45.5	52.3
Earnings (loss)	$(4.5)	$(5.9)	$22.8	$26.6
Volumes (MMdk):				
Sales	14.7	15.3	60.0	60.2
Transportation	29.9	30.3	69.2	68.5
Total throughput	44.6	45.6	129.2	128.7
Degree days (% of normal)*				
Montana-Dakota/Great Plains	109%	130%	107%	104%
Cascade	78%	82%	93%	93%
Intermountain	95%	99%	96%	110%
Average cost of natural gas, including transportation, per dk	$6.05	$4.82	$5.77	$4.77

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

Three Months Ended June 30, 2014 and 2013 The natural gas distribution business experienced a seasonal loss of $4.5 million compared to a seasonal loss of $5.9 million a year ago (a 24 percent improvement). The improvement was largely due to:

- Higher sales margins, including approved rate increases effective in late 2013, offset in part by lower volumes, primarily due to warmer weather
- Lower regulated operation and maintenance expense, which includes $500,000 (after tax) largely related to decreased benefit-related costs and other expenses, offset in part by increased contract services
- Higher other income, which includes $500,000 (after tax) largely related to allowance for funds used during construction

Partially offsetting these increases were higher depreciation, depletion and amortization expense of $700,000 (after tax), primarily resulting from higher property, plant and equipment balances.

The previous table also reflects higher revenue and higher operation and maintenance expense related to nonregulated activity.

Six Months Ended June 30, 2014 and 2013 Natural gas distribution earnings decreased $3.8 million (14 percent) due to:

- The absence in 2014 of the $2.8 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business in March 2013

- Higher operation and maintenance expense, which includes $2.7 million (after tax) largely related to higher payroll and benefit-related costs and higher contract services
- Higher depreciation, depletion and amortization expense of $1.4 million (after tax), as previously discussed

Partially offsetting these decreases were higher retail sales margins, largely resulting from approved rate increases effective in late 2013; as well as higher other income, which includes $800,000 (after tax) largely related to allowance for funds used during construction.

Pipeline and Energy Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Dollars in millions)			
Operating revenues	$51.4	$50.9	$113.3	$97.3
Operating expenses:				
Purchased natural gas sold	13.0	15.8	39.2	28.6
Operation and maintenance	16.9	32.1 *	33.6	49.3 *
Depreciation, depletion and amortization	7.2	7.7	14.3	14.9
Taxes, other than income	3.4	3.5	6.6	6.9
	40.5	59.1	93.7	99.7
Operating income (loss)	10.9	(8.2)	19.6	(2.4)
Earnings (loss)	$5.8	$(6.4)*	$10.1	$(4.1)*
Transportation volumes (MMdk)	53.3	40.3	105.8	77.1
Natural gas gathering volumes (MMdk)	9.7	10.0	19.1	19.9
Customer natural gas storage balance (MMdk):				
Beginning of period	10.4	24.7	26.7	43.7
Net injection (withdrawal)	1.0	.5	(15.3)	(18.5)
End of period	11.4	25.2	11.4	25.2

* Reflects an impairment of coalbed natural gas gathering assets of $14.5 million ($9.0 million after tax).

Three Months Ended June 30, 2014 and 2013 Pipeline and energy services recognized earnings of $5.8 million compared to a loss of $6.4 million for the comparable prior period due to:

- Absence of the 2013 natural gas gathering asset impairment of $9.0 million (after tax)
- 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 $1.2 million (after tax) due to increased transportation rates
- Lower operation and maintenance expense (excluding the asset impairment and Pronghorn-related expense), which includes $800,000 (after tax) largely related to lower legal-related costs

These increases were partially offset by lower storage services revenue of $700,000 (after tax), largely due to lower average storage balances and lower rates.

Six Months Ended June 30, 2014 and 2013 Pipeline and energy services recognized earnings of $10.1 million compared to a loss of $4.1 million for the comparable prior period due to:

- Absence of the 2013 natural gas gathering asset impairment of $9.0 million (after tax)
- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, primarily due to higher volumes and prices
- Higher earnings of $2.0 million (after tax) due to increased transportation rates and volumes
- Lower operation and maintenance expense (excluding the asset impairment and Pronghorn-related expense), which includes $1.1 million (after tax) largely related to lower legal-related costs

These increases were partially offset by lower storage services revenue of $1.3 million (after tax), largely due to lower average storage balances.

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

Exploration and Production

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Dollars in millions, where applicable)			
Operating revenues:				
Oil	$127.2	$105.9	$240.8	$205.9
NGL	6.3	6.2	13.2	13.7
Natural gas	21.6	23.2	52.1	42.4
Realized gain (loss) on commodity derivatives	(10.3)	1.3	(17.1)	5.6
Unrealized gain (loss) on commodity derivatives	(5.2)	13.0	(11.9)	7.2
	139.6	149.6	277.1	274.8
Operating expenses:				
Operation and maintenance:				
Lease operating costs	23.9	22.0	48.0	42.8
Gathering and transportation	3.1	4.2	5.4	8.5
Other	11.8	10.3	23.7	20.4
Depreciation, depletion and amortization	52.9	45.1	102.4	88.3
Taxes, other than income:				
Production and property taxes	14.2	12.3	27.1	23.9
Other	.2	.3	.6	.6
	106.1	94.2	207.2	184.5
Operating income	33.5	55.4	69.9	90.3
Earnings	$19.2	$33.0	$40.1	$53.3
Production:				
Oil (MBbls)	1,366	1,201	2,646	2,319
NGL (MBbls)	167	191	331	392
Natural gas (MMcf)	5,756	6,987	11,034	13,700
Total production (MBOE)	2,492	2,557	4,816	4,995
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):				
Oil (per Bbl)	$93.06	$88.12	$90.99	$88.75
NGL (per Bbl)	$37.67	$32.26	$39.94	$34.86
Natural gas (per Mcf)	$3.76	$3.33	$4.72	$3.10
Average realized prices (including realized gain/loss on commodity derivatives):				
Oil (per Bbl)	$87.03	$90.55	$86.43	$91.18
NGL (per Bbl)	$37.67	$32.26	$39.94	$34.86
Natural gas (per Mcf)	$3.40	$3.09	$4.27	$3.09
Average depreciation, depletion and amortization rate, per BOE	$20.45	$16.90	$20.45	$16.90
Production costs, including taxes, per BOE:				
Lease operating costs	$9.57	$8.59	$9.97	$8.57
Gathering and transportation	1.24	1.66	1.13	1.71
Production and property taxes	5.68	4.81	5.63	4.78
	$16.49	$15.06	$16.73	$15.06

Three Months Ended June 30, 2014 and 2013 Exploration and production earnings decreased $13.8 million (42 percent) due to:

- Unrealized loss on commodity derivatives of $3.3 million (after tax) in 2014 compared to an unrealized gain on commodity derivatives of $8.2 million (after tax) in 2013
- A loss of $7.3 million (after tax) resulting from a realized commodity derivative loss in 2014 compared to a realized commodity derivative gain in 2013
- Higher depreciation, depletion and amortization expense of $4.9 million (after tax), largely related to higher depletion rates
- Decreased natural gas production of 18 percent, largely due to the sale of non-strategic assets

Partially offsetting these decreases were:

- Increased oil production of 14 percent, primarily related to the Powder River Basin acquisition
- Increased average realized oil prices of 6 percent, excluding gain/loss on commodity derivatives

Six Months Ended June 30, 2014 and 2013 Exploration and production earnings decreased $13.2 million (25 percent) due to:

- A loss of $14.3 million (after tax) resulting from a realized commodity derivative loss in 2014 compared to a realized commodity derivative gain in 2013
- Unrealized loss on commodity derivatives of $7.5 million (after tax) in 2014 compared to an unrealized gain on commodity derivatives of $4.6 million (after tax) in 2013
- Higher depreciation, depletion and amortization expense of $8.9 million (after tax), primarily related to higher depletion rates
- Decreased natural gas production of 19 percent, largely due to the sale of non-strategic assets
- Higher lease operating expenses of $3.3 million (after tax), primarily in the Paradox Basin and Bakken areas
- Higher general and administrative expenses of $2.0 million (after tax), primarily related to higher professional services and higher payroll-related costs

Partially offsetting these decreases were:

- Increased oil production of 14 percent, primarily related to drilling activity in the Paradox Basin and the Powder River Basin acquisition
- Higher average realized natural gas prices of 52 percent, excluding gain/loss on commodity derivatives
- Higher average realized oil prices of 3 percent, excluding gain/loss on commodity derivatives

Construction Materials and Contracting

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(Dollars in millions)			
Operating revenues	$442.6	$431.3	$611.0	$597.6
Operating expenses:				
Operation and maintenance	393.4	381.2	569.1	547.9
Depreciation, depletion and amortization	17.4	18.7	35.0	37.7
Taxes, other than income	10.6	10.6	18.9	19.1
	421.4	410.5	623.0	604.7

Operating income (loss)	21.2	20.8	(12.0)	(7.1)
Earnings (loss)	$10.6	$10.0	$(13.0)	$(10.5)
Sales (000's):				
Aggregates (tons)	6,971	6,152	9,800	9,110
Asphalt (tons)	1,474	1,518	1,658	1,667
Ready-mixed concrete (cubic yards)	907	846	1,404	1,326

Three Months Ended June 30, 2014 and 2013 Construction materials and contracting earnings increased $600,000 (5 percent) due to higher earnings of $2.0 million (after tax) resulting from higher aggregate margins and volumes, partially offset by lower earnings resulting from lower construction margins.

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Six Months Ended June 30, 2014 and 2013 Construction materials and contracting experienced a loss of $13.0 million compared to a loss of $10.5 million a year ago (a 23 percent decline). The decline was the result of:

- Lower earnings of $4.7 million (after tax) resulting from lower construction revenues and margins
- Higher selling, general and administrative expenses of $1.8 million (after tax), including higher labor and insurance costs

Partially offsetting the decline were:

- Higher earnings of $2.3 million (after tax) resulting from higher aggregate margins
- Higher earnings resulting from higher other product line margins
- Higher earnings of $600,000 (after tax) resulting from higher asphalt margins

Construction Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Operating revenues	$282.3	$279.6	$556.0	$511.0
Operating expenses:				
Operation and maintenance	246.5	245.9	480.6	444.3
Depreciation, depletion and amortization	3.2	3.0	6.4	6.0
Taxes, other than income	8.3	8.4	18.5	18.0
	258.0	257.3	505.5	468.3
Operating income	24.3	22.3	50.5	42.7
Earnings	$14.3	$12.9	$30.9	$24.6

Three Months Ended June 30, 2014 and 2013 Construction services earnings increased $1.4 million (11 percent) due to higher margins in the Central region, primarily related to outside work.

Six Months Ended June 30, 2014 and 2013 Construction services earnings increased $6.3 million (26 percent) due to:

- Higher workloads and margins in the Western region and higher margins in the Central region, both primarily related to outside work
- Higher electrical supply sales and margins

Partially offsetting these increases were higher selling, general and administrative expense of $1.4 million (after tax), primarily related to higher payroll-related costs.

Other

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Operating revenues	$2.2	$2.3	$4.3	$4.5
Operating expenses:				
Operation and maintenance	1.1	1.4	2.5	2.7
Depreciation, depletion and amortization	.6	.5	1.1	1.0
Taxes, other than income	—	—	—	.1
	1.7	1.9	3.6	3.8
Operating income	.5	.4	.7	.7
Income from continuing operations	1.1	.5	1.3	.9
Income (loss) from discontinued operations, net of tax	.5	(.1)	.5	(.2)
Earnings	$1.6	$.4	$1.8	$.7

Three Months Ended June 30, 2014 and 2013 Other earnings increased $1.2 million, including the effects of the vacation of an arbitration award which is included in discontinued operations as discussed in Note 21.

Six Months Ended June 30, 2014 and 2013 Other earnings increased $1.1 million, as previously discussed.

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Intersegment transactions:				
Operating revenues	$35.3	$37.7	$83.9	$73.9
Purchased natural gas sold	17.7	19.1	56.3	46.1
Operation and maintenance	16.0	15.2	25.3	24.4
Depreciation, depletion and amortization	.2	—	.4	—
Earnings on common stock	.9	2.1	1.2	2.1

For more information on intersegment eliminations, see Note 18.

PROSPECTIVE INFORMATION

The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for certain of the Company's businesses. Many of these highlighted points are "forward-looking statements." There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Part II, Item 1A - Risk Factors, as well as Part I, Item 1A - Risk Factors in the 2013 Annual Report. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's growth and earnings projections.

MDU Resources Group, Inc.

- Adjusted earnings per common share for 2014, diluted, are projected in the range of $1.50 to $1.65, excluding discontinued operations and the unrealized loss of $7.5 million (after tax) on commodity derivatives. Including these adjustments, GAAP earnings guidance for 2014 is in the same range. Unrealized commodity derivatives fair values can fluctuate causing actual GAAP earnings to vary accordingly.

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

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

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

- The Company focuses on creating value through vertical integration between its business units.

- Estimated gross capital expenditures for 2014 are approximately $1.1 billion. The estimate excludes noncontrolling interest capital expenditures related to Dakota Prairie Refining.

Electric and natural gas distribution

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

- Regulatory actions

The Company filed an application February 27, 2014, with the NDPSC requesting approval for a generation resource recovery rider for $7.4 million to recover costs associated with the 88-MW simple-cycle natural gas turbine and associated facilities currently under construction. The estimated project cost is $77 million and the projected in-service date is third quarter 2014. It is located 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. On March 12, 2014, the NDPSC suspended the filing pending further review and a hearing was held May 28, 2014. A work session was held July 18, 2014, to discuss the request. Advance determination of prudence and a Certificate of Public Convenience and Necessity have been received from the NDPSC. For more information, see Note 20.

The Company filed an application September 18, 2013, with the NDPSC for a natural gas rate increase, as discussed in Note 20.

The Company submitted a request April 8, 2014, to the NDPSC to update an environmental cost recovery rider related to costs resulting from the environmental retrofit required to be installed at the Big Stone Station to reflect actual costs incurred through February 2014 and projected costs through June 2015. The NDPSC approved the rider July 10, 2014, for recovery of $8.6 million annually. The Company's share of the cost for the installation is approximately $90 million and is expected to be complete in 2015. The NDPSC had earlier approved advance determination of prudence for recovery of costs on the system. For more information, see Note 20.

- Investments are being made in 2014 totaling approximately $80 million to serve the growing electric and natural gas customer base associated with the Bakken oil development where customer growth is substantially higher than the national average.

- The Company is engaged in a 30-mile, approximately $60 million natural gas line project into the Hanford Nuclear Site in Washington.

- The Company, along with a partner, expects to build a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, about 160 miles. The Company’s share of the cost is estimated at approximately $170 million. The project is a MISO multi-value project. A route application was filed in August 2013 with the state of South Dakota, and in October 2013 with the state of North Dakota. A route permit was approved in North Dakota on July 10, 2014. A route permit hearing was held June 10, 2014, in South Dakota. The project is expected to be complete in 2019.

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

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

Pipeline and energy services

- The Company, in conjunction with Calumet, formed Dakota Prairie Refining, to develop, build and operate Dakota Prairie Refinery. Construction began on the facility in late March 2013 and it is approximately 75 percent complete. When complete, it will process Bakken crude into diesel, which will be marketed within the Bakken region. Other by-products, naphtha and atmospheric tower bottoms, will be railed to other areas. The total project cost estimate is approximately $350 million, with a projected in-service date in late 2014. EBITDA for the first year of operation is projected to be in the range of $70 million to $90 million, to be shared equally with Calumet.

- In January 2014, the Company launched an open season to obtain capacity commitments on a proposed 375-mile natural gas pipeline from western North Dakota to northwestern Minnesota to transport natural gas to markets in eastern North Dakota, Minnesota, Wisconsin, Michigan and other Midwest markets. The pipeline is expected to provide access to additional markets via interconnections with pipelines owned by Great Lakes Gas Transmission, Viking Gas Transmission and potentially TransCanada, in northwestern Minnesota. An interconnection with the Alliance Pipeline system in eastern North Dakota also is possible. Initially the pipeline would transport approximately 400 MMcf per day of natural gas and could be expanded to more than 500 MMcf per day. The project investment is estimated to be approximately $650 million. The open season ended May 30, 2014, and the Company is evaluating the responses received and working with those parties as well as other interested parties. The Company expects to provide a status update on its efforts by this fall. If the project moves forward, following the receipt of necessary permits and regulatory approvals, construction on the new pipeline could begin in 2016 with completion expected in 2017.

- On October 31, 2013, WBI Energy Transmission filed a Section 4 rate case with the FERC, as discussed in Note 20.

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

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

Exploration and production

- The Company expects to spend approximately $620 million in gross capital expenditures in 2014, which is likely to be partially offset by the expected sale of certain Mountrail County, North Dakota assets and other planned asset sales this year.

- For 2014, the Company now expects a 10 to 15 percent increase in oil production, lower than its earlier estimate primarily the result of the expected sale of certain Mountrail County assets. NGL production is expected to decline 20 to 25 percent and natural gas production is expected to be 20 to 25 percent lower compared to a year ago. The declines are primarily the result of the divestment of certain non-strategic natural gas-based properties in 2013 and the expected divestment of the Company's South Texas assets this year. The vast majority of the capital program is focused on growing oil production.

- The Company has a total of three operated drilling rigs deployed on its acreage with two deployed in the Bakken area and one in the Paradox area. There are two non-operated rigs deployed on the Company's Powder River Basin acreage.

- Bakken areas

The Company owns a total of approximately 108,500 net acres of leaseholds in Mountrail and Stark counties, North Dakota and Richland County, Montana, assuming the divestment of 4,363 net acres in Mountrail County. The Middle Bakken and Three Forks formations are targeted in North Dakota and the Red River formation is targeted in Montana.

Capital expenditures are expected to total approximately $125 million in 2014, excluding the proceeds from the pending sale of Mountrail County acreage.

Net oil production for the second quarter was approximately 7,600 BOPD.

The Company has been testing two alternative completion techniques; plug and perforation and coil tubing with cemented liners. The coil tubing with cemented liner technique is encouraging and focus is on optimizing this approach.

- Paradox Basin, Utah
The Company owns approximately 140,000 net acres of leaseholds, including its acquisitions of 35,000 net acres of leaseholds in February 2014, and 11,000 net acres of leaseholds in April 2014 and has an option to earn another 20,000 acres.

Capital expenditures are expected to total approximately $150 million in 2014.

Well costs range from $8 million to $11 million per well depending upon lateral lengths. Estimated ultimate recoveries are increasing with the upper range now at 1.7 MMBbls of oil per well.

The Cane Creek Unit 12-1 well has cumulative production of 740 MBbls of oil since it began producing in September 2012. Artificial lift facilities have recently been installed.

Net oil production for second quarter was approximately 3,290 BOPD, up 42 percent from second quarter 2013 and down 8 percent from first quarter 2014. Operational issues/downtime on several high-rate wells occurred during the quarter, which have now been broadly resolved with the installation of artificial lift. Drilling on multi-well pads, which defers completion, and two low-rate fringe acreage tests have delayed production growth. Higher growth is expected in third quarter 2014. The second drilling rig will return when sufficient permits are in place to sustain two rigs.

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

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

Capital expenditures are expected to total approximately $260 million in 2014, including the acquisition costs, related closing adjustments and drilling capital.

Net production for the second quarter 2014 was 2,000 BOE per day (75 percent oil), up 23 percent from late March 2014 average net production of 1,630 BOE per day.

- Earnings guidance reflects estimated average NYMEX index prices for August through December 2014 in the range of $96 to $102 per Bbl of crude oil, and $4.00 to $5.00 per Mcf of natural gas. Estimated prices for NGL are in the range of $37 to $40 per Bbl.

- Derivatives:
For July through December 2014, 12,000 BOPD at a weighted average price of $96.47.

For July through December 2014, 40,000 MMBtu of natural gas per day at a weighted average price of $4.10.

For January through March 2015, 3,000 BOPD at a weighted average price of $98.00.

For 2015, 10,000 MMBtu of natural gas per day at a weighted average price of $4.28.

The commodity derivative instruments that are in place as of August 1, 2014, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (Bbl/MMBtu)	Price (Per Bbl/MMBtu)
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$94.05
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$95.00
Crude Oil	Swap	NYMEX	7/14 - 9/14	184,000	$95.75
Crude Oil	Swap	NYMEX	7/14 - 9/14	184,000	$96.00
Crude Oil	Swap	NYMEX	7/14 - 9/14	92,000	$96.25
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$94.25
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$95.00
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$95.25
Crude Oil	Swap	NYMEX	7/14 - 12/14	368,000	$96.00
Crude Oil	Swap	NYMEX	10/14 - 12/14	276,000	$100.50
Crude Oil	Swap	NYMEX	10/14 - 12/14	184,000	$101.50
Crude Oil	Swap	NYMEX	1/15 - 3/15	270,000	$98.00
Natural Gas	Swap	NYMEX	7/14 - 12/14	3,680,000	$4.13
Natural Gas	Swap	NYMEX	7/14 - 12/14	1,840,000	$4.05
Natural Gas	Swap	NYMEX	7/14 - 12/14	1,840,000	$4.10
Natural Gas	Swap	NYMEX	1/15 - 12/15	3,650,000	$4.28

Construction materials and contracting

- Approximate work backlog as of June 30, 2014, was $764 million, compared to $730 million a year ago. Private work represents 11 percent of construction backlog and public work represents 89 percent of backlog. The backlog includes a variety of projects such as highway grading, paving and underground projects, airports, bridge work and subdivisions.
- The Company's approximate backlog in North Dakota as of June 30, 2014, was $158 million. North Dakota backlog was $165 million a year ago.
- Projected revenues included in the Company's 2014 earnings guidance are in the range of $1.6 billion to $1.8 billion.
- The Company anticipates margins in 2014 to be in line with 2013 margins.
- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, wind towers and geothermal. Initiatives are aimed at capturing additional market share and expanding into new markets.
- As the country's fifth-largest sand and gravel producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.
- Of the seven labor contracts that Knife River was negotiating, as reported in Items 1 and 2 - Business and Properties - General in the 2013 Annual Report, six have been ratified. The one remaining contract is still in negotiation.

Construction services

- Approximate work backlog as of June 30, 2014, was $386 million, compared to $447 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 June 30, 2014, was $11 million. The construction services business did not have any backlog in North Dakota a year ago.
- Projected revenues included in the Company's 2014 earnings guidance are in the range of $1.1 billion to $1.2 billion.
- The Company anticipates margins in 2014 to be in line with 2013 margins.

- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, 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 8, 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 2013 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2013 Annual Report.

LIQUIDITY AND CAPITAL COMMITMENTS

At June 30, 2014, the Company had cash and cash equivalents of $90.3 million and available capacity of $669.8 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 six months of 2014 decreased $23.4 million from the comparable period in 2013 primarily due to higher income taxes paid.

Investing activities Cash flows used in investing activities in the first six months of 2014 increased $175.2 million from the comparable period in 2013. The increase in cash flows used in investing activities was primarily due to higher acquisition-related capital expenditures at the exploration and production business; offset in part by lower ongoing capital expenditures at the exploration and production business.

Financing activities Cash flows provided by financing activities in the first six months of 2014 increased $177.5 million from the comparable period in 2013. The increase in cash flows provided by financing activities was primarily due to the issuance of $132.3 million of common stock; as well as lower repayment of long-term debt of $102.9 million. Partially offsetting this increase were higher dividends paid in 2014 compared to 2013 due to the acceleration of the first quarter 2013 quarterly common stock dividend to 2012.

Defined benefit pension plans

There were no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2013 Annual Report. For more information, see Note 19 and Part II, Item 7 in the 2013 Annual Report.

Capital expenditures

Net capital expenditures for the first six months of 2014 were $579.2 million and are estimated to be approximately $863 million for 2014. Estimated capital expenditures include:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements

- Buildings, land and building improvements
- Pipeline, gathering and other midstream projects
- Further development of existing properties, acquisition of additional leasehold acreage, exploratory drilling and proceeds from the sale of certain assets at the exploration and production segment
- Power generation and transmission opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- The Company's proportionate share of Dakota Prairie Refinery at the pipeline and energy services segment
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimated 2014 capital expenditures referred to previously. The Company expects the 2014 estimated capital expenditures to be funded by various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt and the Company's equity securities.

Capital resources
Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at June 30, 2014. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For more information on the covenants, certain other conditions and cross-default provisions, see Note 16 and Part II, Item 8 - Note 9, in the 2013 Annual Report.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at June 30, 2014:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date
			(In millions)						
MDU Resources Group, Inc.	Commercial paper/ Revolving credit agreement	(a)	$175.0		$79.0	(b)	$—		5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement		$50.0	(c)	$—		$2.2	(d)	7/9/18
Intermountain Gas Company	Revolving credit agreement		$65.0	(e)	$—		$—		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement	(f)	$650.0		$189.0	(b)	$—		5/8/19

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 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 $75.0 million.
(d) The outstanding letter of credit, as discussed in Note 21, reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90.0 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $800.0 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. On May 8, 2014, the Company amended the revolving credit agreement to increase the borrowing limit to $175.0 million and extend the termination date to May 8, 2019. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in the Company's credit ratings have not limited, nor are currently expected to limit, the Company's ability to access the capital markets. If the Company were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Prior to the maturity of the credit agreement, the Company expects that it will negotiate the extension or replacement of this agreement. If the Company is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility become too expensive, which the Company does not currently anticipate, the Company would seek alternative funding.

The Company's coverage of fixed charges including preferred stock dividends was 4.8 times for the 12 months ended June 30, 2014 and December 31, 2013. Due to the $246.8 million after-tax noncash write-downs of oil and natural gas properties in 2012, earnings were insufficient by $19.8 million to cover fixed charges for the 12 months ended June 30, 2013. If the $246.8 million after-tax noncash write-downs were excluded, the coverage of fixed charges including preferred stock dividends would have been 4.5 times for the 12 months ended June 30, 2013.

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

Total equity as a percent of total capitalization was 58 percent, 57 percent and 60 percent at June 30, 2014 and 2013 and December 31, 2013, respectively. This ratio is calculated as the Company's total equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus total equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

On May 20, 2013, the Company entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 7.5 million shares of the Company's common stock. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement. Sales of such common stock may not be made after February 28, 2016. Proceeds from the shares of common stock under the agreement have been and are expected to be used for corporate development purposes and other general corporate purposes. Under the Equity Distribution Agreement, the Company issued 2.2 million shares of stock between April 1, 2014 and June 30, 2014, receiving net proceeds of $72.3 million, 3.7 million shares of stock between January 1, 2014 and June 30, 2014, receiving net proceeds of $122.4 million and a total of 4.2 million shares of stock as of June 30, 2014, receiving net proceeds of $137.0 million.

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

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

Centennial Energy Holdings, Inc. On May 8, 2014, Centennial entered into an amended and restated revolving credit agreement which increased the borrowing limit to $650.0 million and extended the termination date to May 8, 2019. The credit agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on subsidiary indebtedness and the making of certain loans and investments.

Centennial's revolving credit agreement contains cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial 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, the agreement will be in default.

Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the capital markets. If Centennial were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

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

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

WBI Energy Transmission, Inc. WBI Energy Transmission has a $175.0 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at June 30, 2014, which reduced capacity under this uncommitted private shelf agreement.

Off balance sheet arrangements

In connection with the sale of the Brazilian Transmission Lines, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines. For more information, see Note 12.

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 21.

Contractual obligations and commercial commitments

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

The Company's contractual obligations relating to long-term debt at June 30, 2014, increased $332.5 million or 18 percent from December 31, 2013. As of June 30, 2014, the Company's contractual obligations related to long-term debt aggregated $2,187.1 million. The scheduled amounts of redemption (for the twelve months ended June 30, of each year listed) aggregate $42.2 million in 2015; $669.2 million in 2016; $116.0 million in 2017; $63.0 million in 2018; $382.4 million in 2019; and $914.3 million thereafter.

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to the impact of market fluctuations associated with commodity prices, interest rates and foreign currency. The Company has policies and procedures to assist in controlling these market risks and utilizes derivatives to manage a portion of its risk.

For more information on derivative instruments and commodity price risk, see Part II, Item 7A in the 2013 Annual Report, the Consolidated Statements of Comprehensive Income and Notes 9 and 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 on forecasted sales of oil and natural gas production.

The following table summarizes derivative agreements entered into by Fidelity as of June 30, 2014. These agreements call for Fidelity to receive fixed prices and pay variable prices.

	(Forward notional volume and fair value in thousands)		
	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Oil swap agreements maturing in 2014	$96.43	2,208	$(14,793)
Oil swap agreements maturing in 2015	$98.00	270	$(374)
Natural gas swap agreements maturing in 2014	$4.10	7,360	$(2,282)
Natural gas swap agreement maturing in 2015	$4.28	3,650	$260

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

At June 30, 2014, the Company had no outstanding interest rate hedges.

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

At June 30, 2014, the Company had no outstanding foreign currency hedges.

ITEM 4. CONTROLS AND PROCEDURES

The following information includes the evaluation of disclosure controls and procedures by the Company's chief executive officer and the chief financial officer, along with any significant changes in internal controls of the Company.

Evaluation of disclosure controls and procedures
The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in internal controls
No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended June 30, 2014, that has materially affected, or is

reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see Note 21, which is incorporated herein by reference.

ITEM 1A. RISK FACTORS

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

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

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

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

There are no material changes in the Company's risk factors from those reported in Part I, Item 1A - Risk Factors in the 2013 Annual Report other than the risk related to environmental laws and regulations and the risk that the Company's operations could be adversely impacted by 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.

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

The Company is subject to environmental laws and regulations affecting many aspects of its operations, including air quality, water quality, waste management and other environmental considerations. These laws and regulations can increase 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 relating to electric generation operations and oil and natural gas development and processing. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities and private individuals may interpret the Company's legal or regulatory requirements differently and seek injunctive relief or other remedies against the Company. The Company cannot predict the outcome (financial or operational) of any such litigation or administrative proceedings.

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

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

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

On August 16, 2012, the EPA published a final NSPS rule for the oil and natural gas industry. The NSPS rule phases in over two years. The first phase was effective October 15, 2012, and primarily covers natural gas wells that are hydraulically fractured. Under the new rule, gas vapors or emissions from the natural gas wells must be captured or combusted utilizing a high-efficiency device. Additional reporting requirements and control devices covering oil and natural gas production equipment will be phased in for certain new oil and gas facilities with a final effective date of January 1, 2015. This new rule's impacts on Fidelity, WBI Energy Transmission and WBI Energy Midstream are not expected to be material and are likely to include implementing recordkeeping, reporting and testing requirements and purchasing and installing 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 stated 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 January 8, 2014, in the Federal Register, 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 pounds of carbon dioxide per MW hour emissions standard for coal-fired units does not allow any new coal-fired electric generation to be constructed unless carbon dioxide is captured and sequestered.

President Obama 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. On June 18, 2014, the EPA published in the Federal Register a proposed rule limiting carbon dioxide emissions from existing fossil fuel-fired electric generating units and a separate proposed rule limiting carbon dioxide emissions from existing units that are modified or reconstructed.

In the existing source rule, the EPA requires carbon dioxide emission reductions from each state and instructs each state, or group of states that work together, to submit a plan to the EPA by June 30, 2016, that demonstrates how the state will achieve the targeted emission reductions by 2030. The state plans could include performance standards, emissions reductions or limits on generation for each existing fossil fuel-fired generating unit. It is unknown at this time what each state will require for emissions reductions from each Montana-Dakota owned and jointly owned fossil fuel-fired electric generating unit. In the EPA's proposed GHG rule for modified or reconstructed fossil fuel-fired sources, the EPA proposes emissions limits that could potentially be unachievable. Montana-Dakota does not plan to modify or reconstruct any fossil fuel-fired units at this time, but may modify or reconstruct units in the future which must comply with the rule limitations.

The Company’s primary GHG emission is carbon dioxide from fossil fuels combustion 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.

There may also be new treaties, legislation or regulations to reduce GHG emissions that could affect Montana-Dakota's electric utility operations by requiring additional energy conservation efforts or 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 adversely impact 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 by applicable laws and regulations. The Company monitors GHG regulations and the potential for GHG regulations to impact 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: August 8, 2014	BY:	/s/ Doran N. Schwartz Doran N. Schwartz Vice President and Chief Financial Officer
	BY:	/s/ Nathan W. Ring Nathan W. Ring Vice President, Controller and Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.	
4(a)	Second Amendment to Credit Agreement, dated May 8, 2014, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent
4(b)	Third Amended and Restated Credit Agreement, dated May 8, 2014, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto
+10(a)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 5, 2014
+10(b)	Director Compensation Policy, as amended May 15, 2014
+10(c)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of July 15, 2014
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 June 30, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Consolidated Financial Statements, tagged in summary and detail

+ Management contract, compensatory plan or arrangement.

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