MDU RESOURCES GROUP INC
Form 10-Q
August 05, 2016

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, 2016
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____________ to ______________
Commission file number 1-3480
MDU RESOURCES GROUP, INC.
(Exact name of registrant as specified in its charter)

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

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)
(701) 530-1000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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 definitions 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 (Do not check if a smaller reporting company)	Smaller reporting company o

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 July 29, 2016: 195,304,376 shares.

Definitions

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

Abbreviation or Acronym	
2015 Annual Report	Company's Annual Report on Form 10-K for the year ended December 31, 2015
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
Bbl	Barrel
Bombard Mechanical	Bombard Mechanical, LLC, an indirect wholly owned subsidiary of MDU Construction Services
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines
Btu	British thermal unit
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
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
Company	MDU Resources Group, Inc.
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company previously owned by WBI Energy and Calumet (previously included in the Company's refining segment)
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ESCP	Erosion and Sediment Control Plan
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 (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
JTL - Montana	JTL Group, Inc. (Montana Corporation), an indirect wholly owned subsidiary of Knife River
JTL - Wyoming	JTL Group, Inc. (Wyoming Corporation), 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

LTM	LTM, Incorporated, an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
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

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MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million Btu
MMdk	Million dk
MNPUC	Minnesota Public Utilities Commission
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
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
Nevada State District Court	District Court Clark County, Nevada
NGL	Natural gas liquids
Notice of Civil Penalty	Notice of Civil Penalty Assessment and Order
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PRP	Potentially Responsible Party
RIN	Renewable Identification Number
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended
Tesoro	Tesoro Refining & Marketing Company LLC
United States District Court for the District of Montana	United States District Court for the District of Montana, Great Falls Division
United States Supreme Court	Supreme Court of the United States
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
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
WYPSC	Wyoming Public Service Commission

Introduction

The Company is a regulated energy delivery and construction materials and services business, 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 midstream segment and Fidelity, formerly the Company's exploration and production business), Knife River (construction materials and contracting segment), MDU Construction Services (construction services segment), Centennial Resources and Centennial Capital (both reflected in the Other category).

In the second quarter of 2016, the Company sold all of the outstanding membership interests in Dakota Prairie Refining and exited that line of business. Therefore, the results of Dakota Prairie Refining are reflected in discontinued operations, other than certain general and administrative costs and interest expense which are reflected in the Other category.

In the second quarter of 2015, the Company announced its plan to market Fidelity and exit that line of business. The Company completed the sale of all of its marketed assets. Therefore, the results of Fidelity are reflected in discontinued operations, other than certain general and administrative costs and interest expense which are reflected in the Other category.

For more information on the Company's business segments and discontinued operations, see Notes 10 and 15.

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Part I -- Financial Information
Item 1. Financial Statements
MDU Resources Group, Inc.
Consolidated Statements of Income
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands, except per share amounts)			
Operating revenues:				
Electric, natural gas distribution and regulated pipeline and midstream	$206,052	$215,678	$591,918	$622,167
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	837,896	722,361	1,312,245	1,176,717
Total operating revenues	1,043,948	938,039	1,904,163	1,798,884
Operating expenses:				
Fuel and purchased power	15,914	19,327	37,925	43,146
Purchased natural gas sold	47,439	66,590	208,474	267,739
Operation and maintenance:				
Electric, natural gas distribution and regulated pipeline and midstream	77,078	70,258	151,703	138,800
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	722,742	635,781	1,165,243	1,059,612
Depreciation, depletion and amortization	54,248	51,336	109,132	102,922
Taxes, other than income	37,562	35,038	80,736	76,648
Total operating expenses	954,983	878,330	1,753,213	1,688,867
Operating income	88,965	59,709	150,950	110,017
Other income	872	2,123	1,921	2,373
Interest expense	22,219	23,389	45,087	46,456
Income before income taxes	67,618	38,443	107,784	65,934
Income taxes	21,320	12,382	29,620	19,333
Income from continuing operations	46,298	26,061	78,164	46,601
Loss from discontinued operations, net of tax (Note 10)	(276,102)	(263,419)	(294,138)	(593,404)
Net loss	(229,804)	(237,358)	(215,974)	(546,803)
Loss from discontinued operations attributable to noncontrolling interest (Note 10)	(120,651)	(7,754)	(131,691)	(11,282)
Dividends declared on preferred stocks	171	171	343	342
Loss on common stock	$(109,324)	$(229,775)	$(84,626)	$(535,863)
Earnings (loss) per common share - basic:				
Earnings before discontinued operations	$.24	$.13	$.40	$.24
Discontinued operations attributable to the Company, net of tax	(.80)	(1.31)	(.83)	(2.99)
Earnings (loss) per common share - basic	$(.56)	$(1.18)	$(.43)	$(2.75)
Earnings (loss) per common share - diluted:				
Earnings before discontinued operations	$.24	$.13	$.40	$.24
Discontinued operations attributable to the Company, net of tax	(.80)	(1.31)	(.83)	(2.99)
Earnings (loss) per common share - diluted	$(.56)	$(1.18)	$(.43)	$(2.75)
Dividends declared per common share	$.1875	$.1825	$.3750	$.3650
Weighted average common shares outstanding - basic	195,304	194,805	195,294	194,643
Weighted average common shares outstanding - diluted	195,699	194,838	195,678	194,675

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,	
	2016	2015	2016	2015
	(In thousands)			
Net loss	$(229,804)	$(237,358)	$(215,974)	$(546,803)
Other comprehensive income (loss):				
Reclassification adjustment for loss on derivative instruments included in net loss, net of tax of $56 and $60 for the three months ended and $114 and $121 for the six months ended in 2016 and 2015, respectively	91	100	183	199
Amortization of postretirement liability (gains) losses included in net periodic benefit cost, net of tax of $150 and $420 for the three months ended and $(819) and $649 for the six months ended in 2016 and 2015, respectively	248	584	(1,347)	959
Foreign currency translation adjustment:				
Foreign currency translation adjustment recognized during the period, net of tax of $19 and $6 for the three months ended and $33 and $(63) for the six months ended in 2016 and 2015, respectively	31	9	56	(103)
Reclassification adjustment for loss on foreign currency translation adjustment included in net loss, net of tax of $0 and $0 for the three months ended and $0 and $491 for the six months ended in 2016 and 2015, respectively	—	—	—	802
Foreign currency translation adjustment	31	9	56	699
Net unrealized gain (loss) on available-for-sale investments:				
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(16) and $(23) for the three months ended and $(10) and $(34) for the six months ended in 2016 and 2015, respectively	(30)	(43)	(19)	(64)
Reclassification adjustment for loss on available-for-sale investments included in net loss, net of tax of $19 and $15 for the three months ended and $37 and $34 for the six months ended in 2016 and 2015, respectively	36	28	69	64
Net unrealized gain (loss) on available-for-sale investments	6	(15)	50	—
Other comprehensive income (loss)	376	678	(1,058)	1,857
Comprehensive loss	(229,428)	(236,680)	(217,032)	(544,946)
Comprehensive loss from discontinued operations attributable to noncontrolling interest	(120,651)	(7,754)	(131,691)	(11,282)
Comprehensive loss attributable to common stockholders	$(108,777)	$(228,926)	$(85,341)	$(533,664)

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

MDU Resources Group, Inc.
Consolidated Balance Sheets
(Unaudited)

	June 30, 2016	June 30, 2015	December 31, 2015
(In thousands, except shares and per share amounts)			
Assets			
Current assets:			
Cash and cash equivalents	$85,117	$143,527	$83,903
Receivables, net	637,166	597,606	582,475
Inventories	265,849	290,239	240,551
Deferred income taxes	33,938	38,087	33,121
Prepayments and other current assets	50,309	66,676	29,528
Current assets held for sale	85,124	147,162	54,847
Total current assets	1,157,503	1,283,297	1,024,425
Investments	124,531	119,446	119,704
Property, plant and equipment	6,526,563	6,131,044	6,387,702
Less accumulated depreciation, depletion and amortization	2,551,941	2,438,005	2,489,322
Net property, plant and equipment	3,974,622	3,693,039	3,898,380
Deferred charges and other assets:			
Goodwill	641,527	635,204	635,204
Other intangible assets, net	7,160	8,506	7,342
Other	360,520	352,728	351,603
Noncurrent assets held for sale	123,721	1,160,657	565,509
Total deferred charges and other assets	1,132,928	2,157,095	1,559,658
Total assets	$6,389,584	$7,252,877	$6,602,167
Liabilities and Equity			
Current liabilities:			
Long-term debt due within one year	$58,598	$415,539	$238,539
Accounts payable	275,791	234,894	286,061
Taxes payable	45,749	37,365	46,880
Dividends payable	36,791	35,734	36,784
Accrued compensation	56,390	47,771	45,192
Other accrued liabilities	196,701	164,427	167,322
Current liabilities held for sale	32,357	145,211	130,375
Total current liabilities	702,377	1,080,941	951,153
Long-term debt	1,928,709	1,886,804	1,557,624
Deferred credits and other liabilities:			
Deferred income taxes	700,539	739,342	696,750
Other liabilities	820,349	757,108	812,342
Noncurrent liabilities held for sale	—	101,790	63,750
Total deferred credits and other liabilities	1,520,888	1,598,240	1,572,842
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	195,843	195,411	195,805
Shares issued - 195,843,297 at June 30, 2016, 195,411,301 at			

June 30, 2015 and 195,804,665 at December 31, 2015			
Other paid-in capital	1,230,342	1,220,615	1,230,119
Retained earnings	838,257	1,155,777	996,355
Accumulated other comprehensive loss	(38,206)	(40,246)	(37,148)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)	(3,626)
Total common stockholders' equity	2,222,610	2,527,931	2,381,505
Total stockholders' equity	2,237,610	2,542,931	2,396,505
Noncontrolling interest	—	143,961	124,043
Total equity	2,237,610	2,686,892	2,520,548
Total liabilities and equity	$6,389,584	$7,252,877	$6,602,167

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, 2016	2015
	(In thousands)	
Operating activities:		
Net loss	$(215,974)	$(546,803)
Loss from discontinued operations, net of tax	(294,138)	(593,404)
Income from continuing operations	78,164	46,601
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	109,132	102,922
Deferred income taxes	3,608	11,119
Changes in current assets and liabilities, net of acquisitions:		
Receivables	(44,909)	(10,712)
Inventories	(23,189)	(47,559)
Other current assets	(20,555)	24,192
Accounts payable	7,339	14,447
Other current liabilities	33,214	(4,335)
Other noncurrent changes	(14,626)	(16,479)
Net cash provided by continuing operations	128,178	120,196
Net cash provided by (used in) discontinued operations	(25,529)	74,068
Net cash provided by operating activities	102,649	194,264
Investing activities:		
Capital expenditures	(220,098)	(272,514)
Net proceeds from sale or disposition of property and other	14,778	29,550
Investments	(262)	1,208
Net cash used in continuing operations	(205,582)	(241,756)
Net cash provided by (used in) discontinued operations	28,040	(160,622)
Net cash used in investing activities	(177,542)	(402,378)
Financing activities:		
Issuance of long-term debt	387,625	320,988
Repayment of long-term debt	(196,771)	(35,137)
Proceeds from issuance of common stock	—	14,499
Dividends paid	(73,575)	(71,294)
Tax withholding on stock-based compensation	(323)	—
Net cash provided by continuing operations	116,956	229,056
Net cash provided by (used in) discontinued operations	(40,852)	62,229
Net cash provided by financing activities	76,104	291,285
Effect of exchange rate changes on cash and cash equivalents	3	(123)
Increase in cash and cash equivalents	1,214	83,048
Cash and cash equivalents -- beginning of year	83,903	60,479
Cash and cash equivalents -- end of period	$85,117	$143,527

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

MDU Resources Group, Inc.
Notes to Consolidated
Financial Statements
June 30, 2016 and 2015
(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 2015 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 2015 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, 2016, up to the date of issuance of these consolidated interim financial statements.

On June 24, 2016, WBI Energy entered into a membership interest purchase agreement with Tesoro to sell all of the outstanding membership interests in Dakota Prairie Refining to Tesoro. WBI Energy and Calumet each previously owned 50 percent of the Dakota Prairie Refining membership interests and were equal members in building and operating Dakota Prairie Refinery. To effectuate the sale, WBI Energy acquired Calumet’s 50 percent membership interest in Dakota Prairie Refining on June 27, 2016. The sale of the membership interests to Tesoro closed on June 27, 2016. The sale of Dakota Prairie Refining reduces the Company’s risk by decreasing exposure to commodity prices.

In the second quarter of 2015, the Company began the marketing and sale process of Fidelity with an anticipated sale to occur within one year. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's marketed oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. The sale of Fidelity was part of the Company's strategic plan to grow its capital investments in the remaining business segments and to focus on creating a greater long-term value.

The assets and liabilities for the Company's discontinued operations have been classified as held for sale and the results of operations are shown in loss from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations. For more information on the Company's discontinued operations, see Note 10.

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 $31.7 million, $29.3 million and $27.8 million at June 30, 2016 and 2015, and December 31, 2015, 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, 2016 and 2015, and December 31, 2015, was $11.0 million, $8.6 million and $9.8 million, respectively.

Note 4 - Inventories and natural gas in storage

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. All other inventories are stated at the lower of average cost or market value. 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, 2016	June 30, 2015	December 31, 2015
	(In thousands)		
Aggregates held for resale	$130,544	$123,457	$ 115,854
Asphalt oil	42,591	79,422	36,498
Natural gas in storage (current)	19,689	11,310	21,023
Materials and supplies	20,765	22,594	16,997
Merchandise for resale	18,439	16,140	15,318
Other	33,821	37,316	34,861
Total	$265,849	$290,239	$ 240,551

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 $49.1 million, $49.3 million and $49.1 million at June 30, 2016 and 2015, and December 31, 2015, respectively.

Note 5 - Impairment of long-lived assets

During the second quarter of 2015, the Company recognized an impairment of coalbed natural gas gathering assets at the pipeline and midstream segment of $3.0 million, 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 where there had been continued decline in natural gas development and production activity due to low natural gas prices. The coalbed natural gas gathering assets were written down to their estimated fair value that was determined using the income approach.

For more information on this nonrecurring fair value measurement, see Note 13.

For information regarding impairments related to the Company's discontinued operations, see Note 10.

Note 6 - Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the applicable period. Diluted earnings (loss) per common share were computed by dividing earnings (loss) 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 (loss) was the same for both the basic and diluted earnings (loss) per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings (loss) per share calculations was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)			
Weighted average common shares outstanding - basic	195,304	194,805	195,294	194,643
Effect of dilutive performance share awards	395	33	384	32
Weighted average common shares outstanding - diluted	195,699	194,838	195,678	194,675
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,	
	2016	2015
	(In thousands)	
Interest, net of amounts capitalized and AFUDC - borrowed of $548 and $4,481 in 2016 and 2015, respectively	$44,860	$44,564
Income taxes paid, net	$29,891	$7,147

Noncash investing transactions were as follows:

	June 30,	
	2016	2015
	(In thousands)	
Property, plant and equipment additions in accounts payable	$18,449	$11,576

Note 8 - New accounting standards

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 was to be effective for the Company on January 1, 2017. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance one year and allowing entities to early adopt. With this decision, the guidance will be effective for the Company on January 1, 2018. 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.

Simplifying the Presentation of Debt Issuance Costs In April 2015, the FASB issued guidance on simplifying the presentation of debt issuance costs in the financial statements. This guidance requires entities to present debt issuance costs as a direct deduction to the related debt liability. The amortization of these costs will be reported as interest expense. The guidance was effective for the Company on January 1, 2016, and is to be applied retrospectively. Early adoption of this guidance was permitted, however the Company did not elect to do so. The guidance required a reclassification of the debt issuance costs on the Consolidated Balance Sheets, but did not impact the Company's results of operations or cash flows. As a result of the retrospective application of this change in accounting principle, the Company reclassified debt issuance costs of $100,000 and $100,000 from prepayments and other current assets and $5.4 million and $6.0 million from deferred charges and other assets - other to long-term debt on its Consolidated Balance Sheets at June 30, 2015 and December 31, 2015, respectively.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent) In May 2015, the FASB issued guidance on fair value measurement and disclosure requirements removing the requirement to include investments in the fair value hierarchy for which fair value is measured using the net asset value per share practical expedient. The new guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at net asset value using the practical expedient, and rather limits those disclosures to investments for which the practical expedient has been elected. This guidance was effective for the Company on January 1, 2016, with early adoption permitted. The application of this guidance affected the Company's disclosures; however, it did not impact the Company's results of operations, financial position or cash flows.

Simplifying the Measurement of Inventory In July 2015, the FASB issued guidance regarding inventory that is measured using the first-in, first-out or average cost method. The guidance does not apply to inventory measured using the last-in, first-out or the retail inventory method. The guidance requires inventory within its scope to be measured at the lower of cost or net realizable value, which is the estimated selling price in the normal course of business less reasonably predictable costs of completion, disposal and transportation. These amendments more closely align GAAP with IFRS. This guidance will be effective for the Company on January 1, 2017, and should be applied prospectively with early adoption permitted as of the beginning of an interim or annual reporting period. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position and cash flows.

Balance Sheet Classification of Deferred Taxes In November 2015, the FASB issued guidance regarding the classification of deferred taxes on the balance sheet. The guidance will require all deferred tax assets and liabilities to be classified as noncurrent. These amendments will align GAAP with IFRS. This guidance will be effective for the Company on January 1, 2017, with early adoption permitted. Entities will have the option to apply the guidance prospectively, for all deferred tax assets and liabilities, or

retrospectively. The Company is evaluating the effects the adoption of the new guidance will have on its financial position and disclosures; however, it will not impact the Company's results of operations or cash flows.
Recognition and Measurement of Financial Assets and Financial Liabilities In January 2016, the FASB issued guidance regarding the classification and measurement of financial instruments. The guidance revises the way an entity classifies and measures investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value and amends certain disclosure requirements related to the fair value of financial instruments. This guidance will be effective for the Company on January 1, 2018, with early adoption of certain amendments permitted. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.
Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term on the statement of financial position for leases with terms of more than 12 months. This guidance also requires additional disclosures. This guidance will be effective for the Company on January 1, 2019, and should be applied using a modified retrospective approach with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.
Improvements to Employee Share-Based Payment Accounting In March 2016, the FASB issued guidance regarding simplification of several aspects of the accounting for share-based payment transactions. The guidance will affect the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. This guidance will be effective for the Company on January 1, 2017, with early adoption permitted in any interim or annual period. An entity that elects early adoption must adopt all of the amendments in the same period. Certain amendments of this guidance are to be applied retrospectively and others prospectively. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.
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, 2016	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at beginning of period	$(2,575)	$ (35,852)	$ (175)	$ 20	$ (38,582)
Other comprehensive income (loss) before reclassifications	—	—	31	(30)	1
Amounts reclassified from accumulated other comprehensive loss	91	248	—	36	375
Net current-period other comprehensive income	91	248	31	6	376
Balance at end of period	$(2,484)	$ (35,604)	$ (144)	$ 26	$ (38,206)
Three Months Ended June 30, 2015	Net Unrealized Gain (Loss) on Derivative	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss

	Instruments Qualifying as Hedges				
	(In thousands)				
Balance at beginning of period	$(2,972)	$ (37,843)	$ (139)	$ 30	$ (40,924)
Other comprehensive income (loss) before reclassifications	—	—	9	(43)	(34)
Amounts reclassified from accumulated other comprehensive loss	100	584	—	28	712
Net current-period other comprehensive income (loss)	100	584	9	(15)	678
Balance at end of period	$(2,872)	$ (37,259)	$ (130)	$ 15	$ (40,246)

Six Months Ended June 30, 2016	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at beginning of period	$(2,667)	$ (34,257)	$ (200)	$ (24)	$ (37,148)
Other comprehensive income (loss) before reclassifications	—	—	56	(19)	37
Amounts reclassified from accumulated other comprehensive loss	183	(1,347)	—	69	(1,095)
Net current-period other comprehensive income (loss)	183	(1,347)	56	50	(1,058)
Balance at end of period	$(2,484)	$ (35,604)	$ (144)	$ 26	$ (38,206)

Six Months Ended June 30, 2015	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at beginning of period	$(3,071)	$ (38,218)	$ (829)	$ 15	$ (42,103)
Other comprehensive loss before reclassifications	—	—	(103)	(64)	(167)
Amounts reclassified from accumulated other comprehensive loss	199	959	802	64	2,024
Net current-period other comprehensive income	199	959	699	—	1,857
Balance at end of period	$(2,872)	$ (37,259)	$ (130)	$ 15	$ (40,246)

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
	2016	2015	2016	2015	
	(In thousands)				
Reclassification adjustment for loss on derivative instruments included in net loss:					
Interest rate derivative instruments	$(147)	$(160)	$(297)	$(320)	Interest expense
	56	60	114	121	Income taxes
	(91)	(100)	(183)	(199)	
	(398)	(1,004)	2,166	(1,608)	(a)

Amortization of postretirement liability gains (losses) included in net periodic benefit cost					
	150	420	(819)	649	Income taxes
	(248)	(584)	1,347	(959)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net loss	—	—	—	(1,293)	Other income
	—	—	—	491	Income taxes
	—	—	—	(802)	
Reclassification adjustment for loss on available-for-sale investments included in net loss	(55)	(43)	(106)	(98)	Other income
	19	15	37	34	Income taxes
	(36)	(28)	(69)	(64)	
Total reclassifications	$(375)	$(712)	$1,095	$(2,024)	

(a) Included in net periodic benefit cost. For more information, see Note 16.

Note 10 - Discontinued operations
The assets and liabilities of the Company's discontinued operations have been classified as held for sale and the results of operations are shown in loss from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded.

Dakota Prairie Refining
On June 24, 2016, WBI Energy entered into a membership interest purchase agreement with Tesoro to sell all of the outstanding membership interests in Dakota Prairie Refining to Tesoro. WBI Energy and Calumet each previously owned 50 percent of the Dakota Prairie Refining membership interests and were equal members in building and operating Dakota Prairie Refinery. To effectuate the sale, WBI Energy acquired Calumet’s 50 percent membership interest in Dakota Prairie Refining on June 27, 2016. The sale of the membership interests to Tesoro closed on June 27, 2016. The sale of Dakota Prairie Refining reduces the Company’s risk by decreasing exposure to commodity prices.

In connection with the sale, WBI Energy has cash in an escrow account for RINs obligations, which is included in current assets held for sale on the Consolidated Balance Sheet at June 30, 2016. The Company retained certain liabilities of Dakota Prairie Refining which are reflected in current liabilities held for sale on the Consolidated Balance Sheet at June 30, 2016. Also, Centennial continues to guarantee certain debt obligations of Dakota Prairie Refining; however, Tesoro has agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. For more information related to the guarantee, see Note 18.

The carrying amounts of the major classes of assets and liabilities that are classified as held for sale related to the operations of Dakota Prairie Refining on the Company's Consolidated Balance Sheets were as follows:

	June 30, 2016	June 30, 2015		December 31, 2015	
	(In thousands)				
Assets					
Current assets:					
Cash and cash equivalents	$—	$845		$ 688	
Receivables, net	433	29,639		7,693	
Inventories	—	24,166		13,176	
Deferred income taxes	—	84	(a)	—	
Income taxes receivable	12,550	7,332		2,495	
Prepayments and other current assets	11,083	7,888		6,214	
Total current assets held for sale	24,066	69,954		30,266	
Noncurrent assets:					
Net property, plant and equipment	—	418,885		412,717	
Deferred income taxes	57,644	5,839		5,745	
Other	—	5,729		9,627	
Total noncurrent assets held for sale	57,644	430,453		428,089	
Total assets held for sale	$81,710	$500,407		$ 458,355	
Liabilities					
Current liabilities:					
Short-term borrowings	$—	$26,000		$ 45,500	
Long-term debt due within one year	—	3,000		5,250	
Accounts payable	7,170	38,170		24,468	
Taxes payable	—	1,601		1,391	
Deferred income taxes	—	—		272	
Accrued compensation	—	649		938	
Other accrued liabilities	8,303	932		4,953	
Total current liabilities held for sale	15,473	70,352		82,772	
Noncurrent liabilities:					
Long-term debt	—	66,000		63,750	
Deferred income taxes	—	19,600	(b)	29,314	(b)
Total noncurrent liabilities held for sale	—	85,600		93,064	
Total liabilities held for sale	$15,473	$155,952		$ 175,836	

(a) On the Company's Consolidated Balance Sheet, this amount was reclassified to a current deferred income tax liability and is reflected in current liabilities held for sale.

(b) On the Company's Consolidated Balance Sheets, these amounts were reclassified to noncurrent deferred income tax assets and are reflected in noncurrent assets held for sale.

The Company's deferred tax assets were largely comprised of $137.6 million of federal and state net operating loss carryforwards that expire in 2037 if not utilized.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2016, the fair value assessment was determined using the market approach based on the sale transaction to Tesoro. The fair value assessment indicated an impairment based on the carrying value exceeding the fair value, which resulted in the Company recording an impairment of $251.9 million ($156.7 million after tax) in the quarter ended June 30, 2016. The impairment was included in operating expenses from discontinued operations. The fair value of Dakota Prairie Refining's assets has been categorized as Level 3 in the fair value hierarchy. At June 30, 2016, Dakota Prairie Refining had not incurred any material exit and disposal costs, and does not expect to incur any material exit and disposal costs.

Fidelity

In the second quarter of 2015, the Company began the marketing and sale process of Fidelity with an anticipated sale to occur within one year. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's marketed oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. The sale of Fidelity was part of the Company's strategic plan to grow its capital investments in the remaining business segments and to focus on creating a greater long-term value.

The carrying amounts of the major classes of assets and liabilities that are classified as held for sale related to the operations of Fidelity on the Company's Consolidated Balance Sheets were as follows:

	June 30, 2016	June 30, 2015	December 31, 2015
	(In thousands)		
Assets			
Current assets:			
Receivables, net	$8,207	$33,551	$ 13,387
Inventories	—	6,748	1,308
Commodity derivative instruments	—	2,537	—
Income taxes receivable	52,847	31,033	9,665
Prepayments and other current assets	4	3,423	221
Total current assets held for sale	61,058	77,292	24,581
Noncurrent assets:			
Investments	—	37	37
Net property, plant and equipment	5,507	1,097,576	793,422
Deferred income taxes	61,347	52,017	127,655
Other	161	161	161
Less allowance for impairment of assets held for sale	938	399,987	754,541
Total noncurrent assets held for sale	66,077	749,804	166,734
Total assets held for sale	$127,135	$827,096	$ 191,315
Liabilities			
Current liabilities:			
Accounts payable	$456	$49,400	$ 25,013
Taxes payable	—	4,064	1,052
Deferred income taxes	4,120	1,401	3,620
Accrued compensation	1,459	4,460	13,080
Commodity derivative instruments	—	3,511	—
Other accrued liabilities	10,849	12,107	4,838
Total current liabilities held for sale	16,884	74,943	47,603
Noncurrent liabilities:			
Other liabilities	—	35,790	—
Total noncurrent liabilities held for sale	—	35,790	—
Total liabilities held for sale	$16,884	$110,733	$ 47,603

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2016, the fair value assessment was determined using the income and market approaches. The income approach was determined by using the present value of future estimated cash flows. The market approach was based on market transactions of similar properties. The estimated carrying value exceeded the fair value and the Company recorded an impairment of $900,000 ($600,000 after tax) in the second quarter of 2016. In the first quarter of 2016, the fair value assessment was determined using the market approach largely based on a purchase and sale agreement. The estimated fair value exceeded the carrying value and the Company recorded an impairment reversal of $1.4 million ($900,000 after tax) in the first quarter of 2016. The impairment and impairment reversal were included in operating expenses from discontinued operations. The estimated fair value of Fidelity's assets have been categorized as Level 3 in the fair value hierarchy. In 2015, the Company recorded impairments totaling $754.5 million ($475.4 million after tax) related to the assets and liabilities classified as held for sale, including an impairment of $400.0 million ($252.0 million after tax) during the second quarter of 2015. For more information, see Part II, Item 8 - Note 2, in the 2015 Annual Report.

The Company incurred transaction costs of approximately $300,000 in the first quarter of 2016, and $2.5 million in 2015. In addition to the transaction costs, and due in part to the change in plans to sell the assets of Fidelity rather than sell Fidelity as a company, Fidelity incurred and expensed approximately $3.8 million and $5.6 million of exit and disposal costs for the three and six months ended June 30, 2016, respectively, and has incurred $10.5 million of exit and disposal costs to date. The Company expects to incur an additional $300,000 of exit and disposal costs for the remainder of 2016. The exit and disposal costs are associated with severance and other related matters and exclude the office lease expiration discussed in the following paragraph. The majority of these exit and disposal activities were completed by the end of the second quarter of 2016.

Fidelity vacated its office space in Denver, Colorado. The Company incurred lease payments of approximately $400,000 and $900,000 for the three and six months ended June 30, 2016, respectively. Lease termination payments of $3.2 million and

$3.3 million were made during the second quarter of 2016 and fourth quarter of 2015, respectively. Existing office furniture and fixtures were relinquished to the lessor in the second quarter of 2016.

Historically, the Company used the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and amortized on the units-of-production method based on total proved reserves.

Prior to the oil and natural gas properties being classified as held for sale, capitalized costs were subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, plus the effects of cash flow hedges, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices and exclude cash outflows associated with asset retirement obligations that have been accrued on the balance sheet. If capitalized costs, less accumulated amortization and related deferred income taxes, exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

The Company's capitalized cost under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2015. SEC Defined Prices, adjusted for market differentials, were used to calculate the ceiling test. Accordingly, the Company was required to write down its oil and natural gas producing properties. The Company recorded a $500.4 million ($315.3 million after tax) noncash write-down in operating expenses from discontinued operations in the first quarter of 2015.

Dakota Prairie Refining and Fidelity

The reconciliation of the major classes of income and expense constituting pretax loss from discontinued operations, which includes Dakota Prairie Refining and Fidelity, to the after-tax net loss from discontinued operations on the Company's Consolidated Statements of Income were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)			
Operating revenues	$74,756	$91,468	$122,732	$148,109
Operating expenses	443,756	505,487	513,526	1,086,781
Operating loss	(369,000)	(414,019)	(390,794)	(938,672)
Other income	183	385	387	2,459
Interest expense	832	434	1,753	517
Loss from discontinued operations before income taxes	(369,649)	(414,068)	(392,160)	(936,730)
Income taxes	(93,547)	(150,649)	(98,022)	(343,326)
Loss from discontinued operations	(276,102)	(263,419)	(294,138)	(593,404)
Loss from discontinued operations attributable to noncontrolling interest	(120,651)	(7,754)	(131,691)	(11,282)
Loss from discontinued operations attributable to the Company	$(155,451)	$(255,665)	$(162,447)	$(582,122)

The pretax loss from discontinued operations attributable to the Company, related to the operations of Dakota Prairie Refining, were $244.0 million and $6.8 million for the three months ended and $253.9 million and $9.8 million for the six months ended June 30, 2016 and 2015, respectively.

Note 11 - Goodwill and other intangible assets

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

Six Months Ended June 30, 2016	Balance as of January 1, 2016	*	Goodwill Acquired During the Year	Balance as of June 30, 2016	*
	(In thousands)				
Natural gas distribution	$345,736		$ —	$345,736	

Pipeline and midstream	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	103,441	6,323	109,764
Total	$635,204	$ 6,323	$641,527

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

Six Months Ended June 30, 2015	Balance as of January 1, 2015 *	Goodwill Acquired During the Year	Balance as of June 30, 2015 *
	(In thousands)		
Natural gas distribution	$345,736	$ —	$345,736
Pipeline and midstream	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	103,441	—	103,441
Total	$635,204	$ —	$635,204

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

Year Ended December 31, 2015	Balance as of January 1, 2015 *	Goodwill Acquired During the Year	Balance as of December 31, 2015 *
	(In thousands)		
Natural gas distribution	$345,736	$ —	$ 345,736
Pipeline and midstream	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	103,441	—	103,441
Total	$635,204	$ —	$ 635,204

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

Other amortizable intangible assets were as follows:

	June 30, 2016	June 30, 2015	December 31, 2015
	(In thousands)		
Customer relationships	$17,145	$20,975	$ 20,975
Accumulated amortization	(13,108)	(16,065)	(16,845)
	4,037	4,910	4,130
Noncompete agreements	2,430	4,409	4,409
Accumulated amortization	(1,585)	(3,581)	(3,655)
	845	828	754
Other	7,764	8,300	8,304
Accumulated amortization	(5,486)	(5,532)	(5,846)
	2,278	2,768	2,458
Total	$7,160	$8,506	$ 7,342

Amortization expense for amortizable intangible assets for the three and six months ended June 30, 2016, was $600,000 and $1.3 million, respectively. Amortization expense for amortizable intangible assets for the three and six months ended June 30, 2015, was $700,000 and $1.4 million, respectively. Estimated amortization expense for amortizable intangible assets is $2.5 million in 2016, $2.2 million in 2017, $1.2 million in 2018, $1.0 million in 2019, $500,000 in 2020 and $1.1 million thereafter.

Note 12 - Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. As of June 30, 2016, the Company had no outstanding commodity, 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, 2015, Fidelity held oil swap agreements with total forward notional volumes of 1.1 million Bbl and natural gas swap agreements with total forward notional volumes of 1.8 million MMBtu. At June 30, 2016 and December 31, 2015, Fidelity had no outstanding derivative agreements. Fidelity historically utilized 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. The realized and unrealized gains and losses on the commodity derivative instruments, which were not designated as hedges, were both included in loss from discontinued operations and the associated assets and liabilities were classified as held for sale.

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, 2016 and 2015, and December 31, 2015, 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, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	(In thousands)			
Interest rate derivatives designated as cash flow hedges:				
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	$91	$100	$183	$ 199
Commodity derivatives not designated as hedging instruments:				
Amount of loss recognized in discontinued operations, before tax	—	(8,101)	—	(19,309)

Over the next 12 months net losses of approximately $400,000 (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, 2015
		(In thousands)
Not designated as hedges:		
Commodity derivatives	Current assets held for sale	$ 2,537
Total asset derivatives		$ 2,537

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at June 30, 2015
		(In thousands)
Not designated as hedges:		
Commodity derivatives	Current liabilities held for sale	$ 3,511
Total liability derivatives		$ 3,511

All of the Company's commodity derivative instruments at June 30, 2015, 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, 2015	Gross Amounts Recognized on the Consolidated Balance	Gross Amounts Not Offset on the Consolidated Balance	Net

	Sheets	Sheets	
	(In thousands)		
Assets:			
Commodity derivatives	$2,537	$ (2,537)	$—
Total assets	$2,537	$ (2,537)	$—
Liabilities:			
Commodity derivatives	$3,511	$ (2,537)	$974
Total liabilities	$3,511	$ (2,537)	$974

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Note 13 - Fair value measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $71.4 million, $68.2 million and $67.5 million, at June 30, 2016 and 2015, and December 31, 2015, respectively, are classified as investments on the Consolidated Balance Sheets. The net unrealized gains on these investments were $2.3 million and $3.9 million for the three and six months ended June 30, 2016. The net unrealized gains on these investments were $400,000 and $2.4 million for the three and six months ended June 30, 2015. 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, 2016	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$10,420	$ 52	$ (12)	$10,460
Total	$10,420	$ 52	$ (12)	$10,460

June 30, 2015	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$8,072	$ 29	$ (28)	$8,073
U.S. Treasury securities	2,327	22	—	2,349
Total	$10,399	$ 51	$ (28)	$10,422

December 31, 2015	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$9,128	$ 19	$ (49)	$9,098
U.S. Treasury securities	1,315	—	(6)	1,309
Total	$10,443	$ 19	$ (55)	$10,407

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 are valued at the net asset value of shares held at the end of the quarter, based on published market quotations on active markets, or using other known sources including pricing from outside sources.

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.

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, 2016 and 2015, 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, 2016, 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, 2016
	(In thousands)			
Assets:				
Money market funds	$ —	$ 1,525	$ —	$ 1,525
Insurance contract*	—	71,355	—	71,355
Available-for-sale securities:				
Mortgage-backed securities	—	10,460	—	10,460
Total assets measured at fair value	$ —	$ 83,340	$ —	$ 83,340

* The insurance contract invests approximately 9 percent in common stock of mid-cap companies, 6 percent in common stock of small-cap companies, 17 percent in common stock of large-cap companies, 66 percent in fixed-income investments, 1 percent in target date investments and 1 percent in cash equivalents.

	Fair Value Measurements at June 30, 2015, 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, 2015
	(In thousands)			
Assets:				
Money market funds	$ —	$ 860	$ —	$ 860
Insurance contract*	—	68,187	—	68,187
Available-for-sale securities:				
Mortgage-backed securities	—	8,073	—	8,073
U.S. Treasury securities	—	2,349	—	2,349
Total assets measured at fair value	$ —	$ 79,469	$ —	$ 79,469

* The insurance contract invests approximately 20 percent in common stock of mid-cap companies, 18 percent in common stock of small-cap companies, 28 percent in common stock of large-cap companies, 32 percent in fixed-income investments, 1 percent in target date investments and 1 percent in cash equivalents.

	Fair Value Measurements at December 31, 2015, Using			
	Quoted Prices in	Significant Other Observable	Significant Unobservable Inputs	Balance at December 31, 2015

	Active Markets for Identical Assets (Level 1)	Inputs (Level 2)	(Level 3)	
	(In thousands)			
Assets:				
Money market funds	$ —	$ 1,420	$ —	$ 1,420
Insurance contract*	—	67,459	—	67,459
Available-for-sale securities:				
Mortgage-backed securities	—	9,098	—	9,098
U.S. Treasury securities	—	1,309	—	1,309
Total assets measured at fair value	$ —	$ 79,286	$ —	$ 79,286

* The insurance contract invests approximately 9 percent in common stock of mid-cap companies, 7 percent in common stock of small-cap companies, 19 percent in common stock of large-cap companies, 63 percent in fixed-income investments, 1 percent in target date investments and 1 percent in cash equivalents.

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, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable.

During the second quarter of 2015, 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, 2015, coalbed natural gas gathering assets were written down to the nonrecurring fair value measurement of $1.1 million. The fair value of these coalbed natural gas gathering assets have been categorized as Level 3 in the fair value hierarchy.

The Company performed fair value assessments of the assets and liabilities classified as held for sale. For more information on these Level 3 nonrecurring fair value measurements, see Note 10.

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, 2016	$1,987,307	$2,134,708
Long-term debt at June 30, 2015	$2,302,343	$2,395,095
Long-term debt at December 31, 2015	$1,796,163	$1,819,828

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

Note 14 - Equity

A summary of the changes in equity was as follows:

Six Months Ended June 30, 2016	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
	(In thousands)		
Balance at December 31, 2015	$2,396,505	$ 124,043	$2,520,548
Net loss	(84,283)	(131,691)	(215,974)
Other comprehensive loss	(1,058)	—	(1,058)
Dividends declared on preferred stocks	(343)	—	(343)
Dividends declared on common stock	(73,239)	—	(73,239)
Stock-based compensation	2,015	—	2,015
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	(323)	—	(323)
Net tax deficit on stock-based compensation	(1,664)	—	(1,664)
Contribution from noncontrolling interest	—	7,648	7,648
Balance at June 30, 2016	$2,237,610	$ —	$2,237,610

Six Months Ended June 30, 2015	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
	(In thousands)		
Balance at December 31, 2014	$3,134,041	$ 115,743	$3,249,784
Net loss	(535,521)	(11,282)	(546,803)
Other comprehensive income	1,857	—	1,857
Dividends declared on preferred stocks	(342)	—	(342)
Dividends declared on common stock	(71,078)	—	(71,078)
Stock-based compensation	1,107	—	1,107

Net tax deficit on stock-based compensation	(1,632)	—	(1,632)
Issuance of common stock	14,499	—	14,499
Contribution from noncontrolling interest	—	39,500	39,500
Balance at June 30, 2015	$2,542,931	$ 143,961	$2,686,892

Note 15 - Business segment data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The 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 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 midstream segment provides natural gas transportation, underground storage, gathering and processing 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.

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 provides utility construction services specializing in constructing and maintaining electric and communications lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. This segment also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and other supplies.

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 certain general and administrative costs (reflected in operation and maintenance expense) and interest expense which were previously allocated to the refining business and Fidelity and do not meet the criteria for income (loss) from discontinued operations. The Other category also includes Centennial Resources' former investment in the Brazilian Transmission Lines.

Discontinued operations includes the results of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense as described above. Dakota Prairie Refining refined crude oil and produced and sold diesel fuel, naphtha, ATBs and other by-products of the production process. In the second quarter of 2016, the Company sold all of the outstanding membership interests in Dakota Prairie Refining. Fidelity engaged in oil and natural gas development and production activities in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's marketed oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. For more information on discontinued operations, see Note 10.

The information below follows the same accounting policies as described in Note 1 of the Company's Notes to Consolidated Financial Statements in the 2015 Annual Report. Information on the Company's businesses was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)			
External operating revenues:				
Regulated operations:				
Electric	$73,832	$64,265	$156,755	$136,041
Natural gas distribution	112,770	132,965	412,165	463,538
Pipeline and midstream	19,450	18,448	22,998	22,588
	206,052	215,678	591,918	622,167
Nonregulated operations:				
Pipeline and midstream	10,268	14,749	18,966	27,749

Construction materials and contracting	541,257	495,640	751,108	701,298
Construction services	285,924	211,515	541,424	446,918
Other	447	457	747	752
	837,896	722,361	1,312,245	1,176,717
Total external operating revenues	$1,043,948	$938,039	$1,904,163	$1,798,884

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)			
Intersegment operating revenues:				
Regulated operations:				
Electric	$—	$—	$—	$—
Natural gas distribution	—	—	—	—
Pipeline and midstream	6,594	6,564	27,691	27,625
	6,594	6,564	27,691	27,625
Nonregulated operations:				
Pipeline and midstream	36	110	119	316
Construction materials and contracting	97	1,257	215	2,205
Construction services	77	3,491	539	15,186
Other	1,669	1,792	3,338	3,563
	1,879	6,650	4,211	21,270
Intersegment eliminations	(8,473)	(13,214)	(31,902)	(48,895)
Total intersegment operating revenues	$—	$—	$—	$—
Earnings (loss) on common stock:				
Regulated operations:				
Electric	$8,022	$5,910	$19,141	$14,237
Natural gas distribution	(7,777)	(5,375)	17,464	16,075
Pipeline and midstream	5,564	4,328	10,852	9,685
	5,809	4,863	47,457	39,997
Nonregulated operations:				
Pipeline and midstream	737	(966)	739	89
Construction materials and contracting	33,696	20,136	19,225	5,501
Construction services	6,990	7,003	12,964	11,763
Other	(1,105)	(4,404)	(2,564)	(9,358)
	40,318	21,769	30,364	7,995
Intersegment eliminations	—	(742)	—	(1,733)
Earnings on common stock before loss from discontinued operations	46,127	25,890	77,821	46,259
Loss from discontinued operations, net of tax	(276,102)	(263,419)	(294,138)	(593,404)
Loss from discontinued operations attributable to noncontrolling interest	(120,651)	(7,754)	(131,691)	(11,282)
Total loss on common stock	$(109,324)	$(229,775)	$(84,626)	$(535,863)

Note 16 - Employee benefit plans
Pension and other postretirement plans
The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans were as follows:

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended June 30,	2016	2015	2016	2015
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$—	$46	$374	$425
Interest cost	4,220	4,206	895	889
Expected return on assets	(5,182)	(5,753)	(1,118)	(1,223)
Amortization of prior service cost (credit)	—	18	(343)	(343)
Amortization of net actuarial loss	1,514	1,813	299	553
Curtailment loss	—	258	—	—
Net periodic benefit cost, including amount capitalized	552	588	107	301
Less amount capitalized	121	53	4	33
Net periodic benefit cost	$431	$535	$103	$268

	Pension Benefits		Other Postretirement Benefits	
Six Months Ended June 30,	2016	2015	2016	2015
	(In thousands)			
Components of net periodic benefit cost:				
Service cost	$—	$86	$824	$908
Interest cost	8,610	8,570	1,844	1,803
Expected return on assets	(10,462)	(11,126)	(2,267)	(2,398)
Amortization of prior service cost (credit)	—	36	(686)	(685)
Amortization of net actuarial loss	3,107	3,548	747	1,014
Curtailment loss	—	258	—	—
Net periodic benefit cost, including amount capitalized	1,255	1,372	462	642
Less amount capitalized	202	129	38	62
Net periodic benefit cost	$1,053	$1,243	$424	$580

Prior to 2013, defined pension plan benefits and accruals for all nonunion and certain union plans were frozen. On June 30, 2015, an additional union plan was frozen. As of June 30, 2015, all of the Company's defined pension plans were frozen. These employees were eligible to receive additional defined contribution plan benefits.
Nonqualified benefit plans
In addition to the qualified plan defined pension benefits reflected in the table, the Company also 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. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated upgrades. Vesting for participants not fully vested was retained. The Company's net periodic benefit cost for these plans for the three months ended June 30, 2016, was $1.2 million. The Company's net periodic benefit credit for these plans for the six months ended June 30, 2016, was $700,000, which reflects a curtailment gain of $3.3 million in the first quarter of 2016. The Company's net periodic benefit cost for these plans for the three and six months ended June 30, 2015, was $1.9 million and $3.6 million, respectively.

Multiemployer plans
On September 24, 2014, JTL - Wyoming provided notice to the Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming that it was withdrawing from the plan effective October 26, 2014. The plan administrator will determine JTL - Wyoming's withdrawal liability. For the three months ended March 31, 2015, the Company accrued an additional withdrawal liability of approximately $2.4 million. The cumulative withdrawal liability is currently estimated at $16.4 million which has been accrued on the Consolidated Balance Sheets. The assessed withdrawal liability for this plan may be significantly different from the current estimate. Also, this plan's administrator has alleged that JTL - Wyoming owes additional contributions for periods of time prior to its withdrawal, which could affect its final assessed withdrawal liability. JTL - Wyoming disputes the

plan administrator's demand for additional contributions, and on February 23, 2016, filed a declaratory judgment action in the United States District Court for the District of Wyoming to resolve the dispute.

Note 17 - Regulatory matters

On June 25, 2015, Montana-Dakota filed an application for an electric rate increase with the MTPSC. Montana-Dakota requested a total increase of approximately $11.8 million annually or approximately 21.1 percent above current rates to recover Montana-Dakota’s investments in modifications to generation facilities to comply with new EPA requirements, the addition and/or replacement of capacity and energy requirements and transmission facilities along with the additional depreciation, operation and maintenance expenses and taxes associated with the increases in investment. On February 8, 2016, Montana-Dakota and the interveners to the case filed a stipulation and settlement agreement reflecting an annual increase of $3.0 million effective April 1, 2016, and an additional increase of $4.4 million effective April 1, 2017. A technical hearing was held February 9, 2016. The MTPSC issued an order approving the settlement agreement on March 25, 2016. The approved rates were effective with service rendered on or after April 1, 2016.

On June 30, 2015, Montana-Dakota filed an application with the SDPUC for an electric rate increase. Montana-Dakota requested a total increase of approximately $2.7 million annually or approximately 19.2 percent above current rates to recover Montana-Dakota’s investments in modifications to generation facilities to comply with new EPA requirements, the addition and/or replacement of capacity and energy requirements and transmission facilities along with the additional depreciation, operation and maintenance expenses and taxes associated with the increases in investment. An interim increase of $2.7 million, subject to refund, was implemented January 1, 2016. Montana-Dakota and the SDPUC staff filed a settlement stipulation reflecting an overall annual increase of approximately $1.4 million including a transmission cost recovery rider and an infrastructure rider. A settlement hearing was held on June 7, 2016. The SDPUC issued an order approving the settlement on June 15, 2016. The approved rates were effective with service rendered on and after July 1, 2016. The final approved rate increase was less than the interim rate increase implemented January 1, 2016; therefore, Montana-Dakota will refund the difference with interest to customers no later than October 1, 2016.

On June 30, 2015, Montana-Dakota filed an application for a natural gas rate increase with the SDPUC. Montana-Dakota requested a total increase of approximately $1.5 million annually or approximately 3.1 percent above current rates to recover increased operating expenses along with increased investment in facilities, including the related depreciation expense and taxes, partially offset by an increase in customers and throughput. An interim increase of $1.5 million, subject to refund, was implemented January 1, 2016. Montana-Dakota, the SDPUC staff and other interested parties filed a settlement stipulation reflecting an overall increase of approximately $1.2 million. A settlement hearing was held on June 7, 2016. The SDPUC issued an order approving the settlement on June 15, 2016. The approved rates were effective with service rendered on and after July 1, 2016. The final approved rate increase was less than the interim rate increase implemented January 1, 2016; therefore, Montana-Dakota will refund the difference with interest to customers no later than October 1, 2016.

On September 30, 2015, Great Plains filed an application for a natural gas rate increase with the MNPUC. Great Plains requested a total increase of approximately $1.6 million annually or approximately 6.4 percent above current rates to recover increased operating expenses along with increased investment in facilities, including the related depreciation expense and taxes. Great Plains requested an interim increase of $1.5 million or approximately 6.4 percent, subject to refund. The interim request was approved by the MNPUC on November 30, 2015, and was effective with service rendered on and after January 1, 2016. This matter is pending before the MNPUC. A technical hearing was held April 7, 2016. The MNPUC will deliberate the case on August 5, 2016.

On October 21, 2015, Montana-Dakota filed an application with the NDPSC for an update of an electric generation resource recovery rider and requested a renewable resource cost adjustment rider. Montana-Dakota requested a combined total of approximately $25.3 million with approximately $20.0 million incremental to current rates, to be effective January 1, 2016. This application was resubmitted as two applications on October 26, 2015.

On October 26, 2015, Montana-Dakota filed an application requesting a renewable resource cost adjustment rider of $15.4 million for the recovery of the Thunder Spirit Wind project, placed in service in the fourth quarter of 2015. A settlement was reached with the NDPSC Advocacy Staff whereby Montana-Dakota agreed to a 10.5 percent return on equity on the renewable resource cost adjustment rider, as well as committed to file an electric general rate case no later than September 30, 2016. The renewable resource cost adjustment rider was approved by the NDPSC on January 5, 2016, to be effective January 7, 2016, resulting in an annual increase of $15.1 million on an interim basis pending the determination of the return on equity in the upcoming rate case.

On October 26, 2015, Montana-Dakota filed an application for an update to the electric generation resource recovery rider, which currently includes recovery of Montana-Dakota's investment in the 88-MW simple-cycle natural gas turbine and associated facilities near Mandan, North Dakota. The application proposed to also include the 19 MW of new generation from natural gas-fired internal combustion engines and associated facilities, near Sidney, Montana, placed in service in the fourth quarter of 2015, for a total of $9.9 million or an incremental increase of $4.6 million to be recovered under the rider. On January 25, 2016, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement which would result in an interim increase of $9.7 million or an incremental increase of $4.4 million, subject to refund, a 10.5 percent return on equity and Montana-Dakota would commit to filing an electric general rate case no later than September 30, 2016. A technical hearing on this matter was held on February 4, 2016. On March 9, 2016, the NDPSC issued an order approving the settlement agreement on an interim basis pending the determination in the upcoming rate case to be filed by September 30, 2016, on the return on equity and the net investment authorized for the natural gas-fired internal combustion engines located near Sidney, Montana. The interim rates were effective with service rendered on and after March 15, 2016.

On November 25, 2015, Montana-Dakota filed an application with the NDPSC for an update of its transmission cost adjustment for recovery of MISO-related charges and two transmission projects located in North Dakota, equating to $6.8 million to be collected under the transmission cost adjustment. An update to the transmission cost adjustment was submitted on January 19, 2016, to reflect the provisions of the settlement agreement approved by the NDPSC for the renewable resource cost adjustment rider whereby Montana-Dakota agreed to a 10.5 percent return on equity for this rider as well as committed to file an electric general rate case no later than September 30, 2016. An informal hearing with the NDPSC was held January 20, 2016, regarding this matter. The NDPSC approved the filing on February 10, 2016, on an interim basis with rates to be effective February 12, 2016.

On December 1, 2015, Cascade filed an application with the WUTC for a natural gas rate increase. Cascade requested a total increase of approximately $10.5 million annually or approximately 4.2 percent above current rates. The requested increase includes rate recovery associated with increased infrastructure investment and the associated operating expenses. A settlement in principle has been accepted by all parties reflecting an increase of $4.0 million annually. The WUTC approved the settlement on July 7, 2016. The approved rates are effective with service rendered on or after September 1, 2016.

On April 29, 2016, Cascade filed an application with the OPUC for a natural gas rate increase of approximately $1.9 million annually or approximately 2.8 percent above current rates. The request includes costs associated with pipeline replacement and improvement projects to ensure the integrity of Cascade's system. This matter is pending before the OPUC.

On June 1, 2016, Cascade filed an application with the WUTC for an annual pipeline replacement cost recovery mechanism of $4.6 million or approximately 2.0 percent of additional revenue. The requested increase includes $2.4 million associated with incremental pipeline replacement investments and $2.2 million for an alternative recovery request of incremental operation and maintenance costs associated with a maximum allowable operating pressure validation plan. This matter is pending before the WUTC. If approved, rates will be effective November 1, 2016.

On June 10, 2016, Montana-Dakota filed an application for an increase in electric rates with the WYPSC. Montana-Dakota requested an increase of approximately $3.2 million annually or approximately 13.1 percent above current rates to recover Montana-Dakota's increased investment in facilities along with additional depreciation, operation and maintenance expenses including increased fuel costs, and taxes associated with the increases in investment. This matter is pending before the WYPSC.

Note 18 - 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 $27.4 million, $20.7 million and $19.5 million, which include liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at June 30, 2016 and 2015, and December 31, 2015, respectively, including amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Natural Gas Gathering Operations Omimex filed a complaint against WBI Energy Midstream in Montana Seventeenth Judicial District Court in July 2010 alleging WBI Energy Midstream breached a gathering contract with Omimex as a result of the increased operating pressures demanded by a third party on a natural gas gathering system in Montana. 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. On December 9, 2014, the United States District Court for the District of Montana issued an order determining WBI Energy Midstream breached its obligations as a common carrier and ordered judgment in favor of Omimex for the amount of the stipulated damages. WBI Energy Midstream filed an appeal from the United States District Court for the District of Montana's order and judgment.

Construction Materials Until the fall of 2011 when it discontinued active mining operations at the pit, JTL - Montana 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 - Montana was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL - Montana 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 - Montana was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than $3.7 million plus not more than $5,000 per day from the date of the counterclaim. JTL - Montana submitted an application for amendment of its opencut mining permit in September 2015. JTL - Montana and the Montana DEQ entered into a stipulation for entry of a consent judgment, which was approved by the Montana First Judicial District Court in May 2016, providing for payment of a civil penalty by JTL - Montana of an amount that was not material to the Company and for reclamation of the Target Range Gravel Pit in accordance with the application for amendment of the opencut mining permit previously submitted by JTL - Montana.

Construction Services Bombard Mechanical is a third-party defendant in litigation pending in Nevada State District Court in which the plaintiff, Palms Place, LLC, claims damages attributable to defects in the construction of a 48 story residential tower built in 2008 for which Bombard Mechanical performed plumbing and mechanical work as a subcontractor. On March 12, 2015, the plaintiff presented cost of repair estimates totaling approximately $21 million for alleged plumbing and mechanical system defects associated in whole or in part with work performed by Bombard Mechanical. The matter was settled in June 2016. The settlement provided for a payment by Bombard Mechanical of an amount that was not material to the Company.

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

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

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

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

Coos County The Oregon DEQ issued a Notice of Civil Penalty to LTM dated October 12, 2015, asserting violations of Oregon water quality statutes and rules resulting from the stockpiling and grading of earthen material during 2014 at a site in Coos County and assessing civil penalties totaling approximately $160,000. The Notice of Civil Penalty alleges violations by causing pollution to an intermittent creek, by conducting activity described in a general National Pollutant Discharge Elimination System permit without applying for coverage under the general permit, by placing the earthen materials in a location where they were likely to escape or be carried into waters of the state, and by failing to submit a revised ESCP where there was a change in the size of the project or the location of the disturbed area. The Notice of Civil Penalty also requires LTM to submit a revised ESCP containing measures to prevent further erosion from entering the intermittent creek and to file a work plan outlining how the earthen material will be permanently stabilized or removed. LTM requested a contested case hearing on the Notice of Civil Penalty. LTM and the Oregon

DEQ entered into a mutual agreement and final order which included provisions for a civil penalty of an amount that was not material to the Company and for compliance with a monitoring and maintenance plan for the affected area.
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 released a ROD in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 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 orders reauthorizing the deferred accounting for the 12-month periods starting November 30, 2013, December 1, 2014 and December 1, 2015.
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. The 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 DOE issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.8 million for the remedial investigation, feasibility study and remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site. 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 DOE 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

In June 2016, WBI Energy sold all of the outstanding membership interests in Dakota Prairie Refining. In connection with the sale, Centennial agreed to continue to guarantee certain debt obligations of Dakota Prairie Refining which totaled $66 million at June 30, 2016, and are expected to mature by 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. The estimated fair values of the indemnity asset and guarantee liability are reflected in deferred charges and other assets - other and deferred credits and other liabilities - other, respectively, on the Consolidated Balance Sheets. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining.

In March 2016, a sale agreement was signed to sell Fidelity's assets in the Paradox Basin. In connection with the sale, Centennial agreed to guarantee Fidelity's indemnity obligations associated with the Paradox assets. The guarantee was required by the buyer as a condition to the sale of the Paradox Basin assets.

In 2009, multiple sales agreements were signed to sell the Company's ownership interests in the Brazilian Transmission Lines. In connection with the sale, Centennial agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who were 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.

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, insurance deductibles and loss limits, and certain other guarantees. At June 30, 2016, the fixed maximum amounts guaranteed under these agreements aggregated $114.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $15.5 million in 2016; $35.8 million in 2017; $5.9 million in 2018; $53.4 million in 2019; and $4.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at June 30, 2016. 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, 2016, the fixed maximum amounts guaranteed under these letters of credit aggregated $37.9 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these letters of credit aggregate $9.6 million in 2016 and $28.3 million in 2017. There were no amounts outstanding under the above letters of credit at June 30, 2016. In the event of default under these letter of credit obligations, the subsidiary issuing the letter of credit for that particular obligation would be required to make payments under its letter of credit.

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 or 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, 2016.

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, 2016, approximately $787.4 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 had a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of $300 million, under the agreement were $150 million and $75 million, respectively. Capital commitments for construction in excess of $300 million were shared equally between WBI Energy and Calumet. Dakota Prairie Refining entered into a term loan for project debt financing of $75 million on April 22, 2013. The operating agreement provided for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt was allocated to Calumet. Calumet's cash distributions from Dakota Prairie Refining were decreased by the principal and interest paid on the project debt, while the cash distributions to WBI Energy were not decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan. The net loss attributable to noncontrolling interest on the Consolidated Statements of Income is pretax as Dakota Prairie Refining was a limited liability company. For more information related to the guarantee, see Guarantees in this note.

Dakota Prairie Refining was determined to be a VIE, and the Company had determined that it was the primary beneficiary as it had 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 consolidated Dakota Prairie Refining in its financial statements and recorded a noncontrolling interest for Calumet's ownership interest.

On June 24, 2016, WBI Energy entered into a membership interest purchase agreement with Tesoro to sell all of the outstanding membership interests in Dakota Prairie Refining to Tesoro. To effectuate the sale, WBI Energy acquired Calumet’s 50 percent membership interest in Dakota Prairie Refining on June 27, 2016. The sale of the membership interests to Tesoro closed on June 27, 2016. For more information on the Company's discontinued operations, see Note 10.

Dakota Prairie Refinery commenced operations in May 2015. The assets of Dakota Prairie Refining were used solely for the benefit of Dakota Prairie Refining. The total assets and liabilities of Dakota Prairie Refining were as follows:

	June 30, 2015	December 31, 2015
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$845	$ 851
Accounts receivable	29,639	7,693
Inventories	24,166	13,176
Prepayments and other current assets	7,887	6,215
Total current assets	62,537	27,935
Net property, plant and equipment	431,476	425,123
Deferred charges and other assets:		
Other	5,729	9,626
Total deferred charges and other assets	5,729	9,626
Total assets	$499,742	$ 462,684
Liabilities		
Current liabilities:		
Short-term borrowings	$26,000	$ 45,500
Long-term debt due within one year	3,000	5,250
Accounts payable	38,339	24,766
Taxes payable	1,601	1,391
Accrued compensation	649	938
Other accrued liabilities	932	4,953
Total current liabilities	70,521	82,798
Long-term debt	66,000	63,750
Total liabilities	$136,521	$ 146,548

Fuel Contract Coyote Station entered into a coal supply agreement with Coyote Creek that provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040. Coal purchased under the coal supply agreement is reflected in inventories on the Company's Consolidated Balance Sheets and is recovered from customers as a component of fuel and purchased power.

The 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, 2016, the Company's exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage, was $44.7 million.

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 the regulated energy delivery and construction materials and services businesses 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
- Divestiture of certain assets to fund capital growth projects throughout the Company

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities, revolving credit facilities, the issuance from time to time of debt and equity securities and asset sales. 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 businesses, see Note 15.
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 timely recovery 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 is 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 and could result in the retirement of certain electric generating facilities before they are fully depreciated.
Pipeline and Midstream
Strategy Utilize the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, and investments in and acquisitions of energy-related assets and companies both in its current operating areas and beyond its Rocky Mountain and northern Great Plains base. Incremental and new growth opportunities include: access to new energy sources for storage, gathering and transportation services; expansion of existing storage, gathering and transmission facilities; incremental pipeline projects which expand pipeline capacity; expansion of the pipeline and midstream business to include liquid pipelines and processing activities; and expansion of related energy services.
Challenges Challenges for this segment include: energy price volatility; basis differentials; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other pipeline and midstream companies.
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, are ongoing challenges. 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; growing through organic and acquisition opportunities; and focusing 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.

Additional Information

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 Part II, Item 1A - Risk Factors, as well as Part I, Item 1A - Risk Factors in the 2015 Annual Report. For more information on 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 the consolidated loss by each of the Company's businesses.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(Dollars in millions, where applicable)			
Electric	$8.0	$5.9	$19.2	$14.2
Natural gas distribution	(7.8)	(5.4)	17.5	16.1
Pipeline and midstream	6.3	3.4	11.6	9.8
Construction materials and contracting	33.7	20.1	19.2	5.5
Construction services	7.0	7.0	13.0	11.8
Other	(1.1)	(4.5)	(2.6)	(9.4)
Intersegment eliminations	—	(.7)	—	(1.7)
Earnings before discontinued operations	46.1	25.8	77.9	46.3
Loss from discontinued operations, net of tax	(276.1)	(263.4)	(294.2)	(593.4)
Loss from discontinued operations attributable to noncontrolling interest	(120.7)	(7.8)	(131.7)	(11.2)
Loss on common stock	$(109.3)	$(229.8)	$(84.6)	$(535.9)
Earnings (loss) per common share – basic:				
Earnings before discontinued operations	$.24	$.13	$.40	$.24
Discontinued operations attributable to the Company, net of tax	(.80)	(1.31)	(.83)	(2.99)
Earnings (loss) per common share – basic	$(.56)	$(1.18)	$(.43)	$(2.75)
Earnings (loss) per common share – diluted:				
Earnings before discontinued operations	$.24	$.13	$.40	$.24
Discontinued operations attributable to the Company, net of tax	(.80)	(1.31)	(.83)	(2.99)
Earnings (loss) per common share – diluted	$(.56)	$(1.18)	$(.43)	$(2.75)

Three Months Ended June 30, 2016 and 2015 The Company recognized a consolidated loss of $109.3 million for the quarter ended June 30, 2016, compared to a consolidated loss of $229.8 million from the comparable prior period largely due to:

- Discontinued operations which reflect the absence in 2016 of a fair value impairment of the exploration and production business's assets of $252.0 million (after tax) in 2015, offset in part by a fair value impairment of Dakota Prairie Refining of $156.7 million (after tax) in 2016
- Higher construction revenues and margins, higher asphalt and ready-mixed concrete margins and volumes and higher other product line margins at the construction materials and contracting business

- Other reflects lower operation and maintenance expense and lower interest expense, which have been reduced with the sale of Fidelity's marketed oil and natural gas assets
- Higher electric retail sales margins, largely the result of approved regulatory recovery trackers related to capital investments at the electric business
- The absence in 2016 of an impairment of coalbed natural gas gathering assets at the pipeline and midstream business

Partially offsetting these increases were lower natural gas sales margins related to decreased retail sales volumes of 6 percent resulting from warmer weather and decreased transportation volumes of 13 percent at the natural gas distribution business.

Six Months Ended June 30, 2016 and 2015 The Company recognized a consolidated loss of $84.6 million for the six months ended June 30, 2016, compared to a consolidated loss of $535.9 million from the comparable prior period largely due to:

- Discontinued operations which reflect the absence in 2016 of a noncash write-down of oil and natural gas properties of $315.3 million (after tax) and a fair value impairment of the exploration and production business's assets of $252.0 million (after tax) in 2015, offset in part by a fair value impairment of Dakota Prairie Refining of $156.7 million (after tax) in 2016
- Higher construction revenues and margins, higher asphalt and ready-mixed concrete margins and volumes and higher other product line margins at the construction materials and contracting business
- Other reflects lower operation and maintenance expense and lower interest expense, which have been reduced with the sale of Fidelity's marketed oil and natural gas assets
- Higher retail sales margins, largely the result of approved regulatory recovery trackers related to capital investments, offset in part by decreased electric sales volumes of 4 percent to all customer classes at the electric business
- The absence in 2016 of an impairment of coalbed natural gas gathering assets at the pipeline and midstream business

Financial and Operating Data

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

Electric

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(Dollars in millions, where applicable)			
Operating revenues	$73.8	$64.3	$156.8	$136.0
Operating expenses:				
Fuel and purchased power	15.9	19.3	37.9	43.1
Operation and maintenance	28.8	22.5	55.8	43.6
Depreciation, depletion and amortization	12.4	9.3	25.3	18.6
Taxes, other than income	3.3	3.0	6.6	6.1
	60.4	54.1	125.6	111.4
Operating income	13.4	10.2	31.2	24.6
Earnings	$8.0	$5.9	$19.2	$14.2
Retail sales (million kWh)	732.1	745.0	1,594.5	1,652.7
Average cost of fuel and purchased power per kWh	$.020	$.024	$.022	$.024

Three Months Ended June 30, 2016 and 2015 Electric earnings increased $2.1 million (36 percent) due to:

- Higher retail sales margins, largely the result of approved regulatory recovery trackers related to capital investments
- Favorable income tax changes, which include $2.4 million due to higher production tax credits

Partially offsetting these increases were:

- Higher depreciation, depletion and amortization expense of $1.9 million (after tax) due to increased property, plant and equipment balances
- Lower other income, which includes $1.4 million (after tax) primarily related to AFUDC
- Higher interest expense, which includes $1.2 million (after tax) largely the result of higher long-term debt
- Higher operation and maintenance expense, which includes $700,000 (after tax) primarily due higher payroll-related costs

The previous table also reflects higher operation and maintenance expense due to higher transmission costs being recovered in an approved transmission tracker.

Six Months Ended June 30, 2016 and 2015 Electric earnings increased $5.0 million (34 percent) due to:

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- Higher retail sales margins, largely the result of approved regulatory recovery trackers related to capital investments, offset in part by decreased electric sales volumes of 4 percent to all customer classes
- Favorable income tax changes, which include $4.6 million due to higher production tax credits

Partially offsetting these increases were:

- Higher depreciation, depletion and amortization expense of $4.1 million (after tax) due to increased property, plant and equipment balances

- Lower other income, which includes $2.2 million (after tax) primarily related to AFUDC
- Higher interest expense, which includes $2.1 million (after tax) largely the result of higher long-term debt

The previous table also reflects higher operation and maintenance expense due to higher transmission costs being recovered in an approved transmission tracker.

Natural Gas Distribution

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(Dollars in millions, where applicable)			
Operating revenues	$112.8	$133.0	$412.2	$463.5
Operating expenses:				
Purchased natural gas sold	54.0	73.1	236.1	295.2
Operation and maintenance	38.3	37.4	77.1	75.8
Depreciation, depletion and amortization	16.6	14.7	32.9	29.3
Taxes, other than income	9.6	10.0	26.4	26.6
	118.5	135.2	372.5	426.9
Operating income (loss)	(5.7)	(2.2)	39.7	36.6
Earnings (loss)	$(7.8)	$(5.4)	$17.5	$16.1
Volumes (MMdk):				
Sales	12.9	13.7	53.2	52.6
Transportation	30.5	35.1	71.8	70.2
Total throughput	43.4	48.8	125.0	122.8
Degree days (% of normal)*				
Montana-Dakota/Great Plains	96%	92%	83%	87%
Cascade	56%	80%	80%	78%
Intermountain	81%	86%	92%	85%
Average cost of natural gas, including transportation, per dk	$4.18	$5.34	$4.44	$5.61

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

Three Months Ended June 30, 2016 and 2015 Natural gas distribution experienced a seasonal loss of $7.8 million compared to a seasonal loss of $5.4 million a year ago (45 percent higher loss). The higher loss was the result of:

- Higher depreciation, depletion and amortization expense of $1.2 million (after tax), primarily resulting from increased property, plant and equipment balances
- Lower natural gas sales margins related to decreased retail sales volumes of 6 percent resulting from warmer weather and decreased transportation volumes of 13 percent, offset in part by final and interim rate increases
- Higher regulated operation and maintenance expense, which includes $900,000 (after tax) largely higher payroll-related costs

The previous table also reflects lower operation and maintenance expense related to nonutility project activity, as well as the pass-through of lower natural gas prices which are reflected in the decrease in both sales revenue and purchased natural gas sold in 2016.

Six Months Ended June 30, 2016 and 2015 Natural gas distribution earnings increased $1.4 million (9 percent) due to higher natural gas sales margins resulting from higher retail sales volumes of 1 percent to residential and commercial customers and final and interim rate increases as well as increased transportation volumes.

Partially offsetting the increase were:

- Higher depreciation, depletion and amortization expense of $2.3 million (after tax), primarily resulting from increased property, plant and equipment balances
-

Higher regulated operation and maintenance expense, which includes $1.5 million (after tax) largely higher payroll-related costs
- Lower other income, which includes $400,000 (after tax) primarily related to AFUDC
- Higher interest expense, which includes $400,000 (after tax) primarily related to lower AFUDC - borrowed

The previous table also reflects lower operation and maintenance expense related to nonutility project activity, as well as the pass-through of lower natural gas prices which are reflected in the decrease in both sales revenue and purchased natural gas sold in 2016.

Pipeline and Midstream

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(Dollars in millions)			
Operating revenues	$36.3	$39.8	$69.7	$78.3
Operating expenses:				
Operation and maintenance	15.1	21.4	29.0	36.7
Depreciation, depletion and amortization	6.1	7.3	12.4	14.7
Taxes, other than income	3.1	3.3	5.8	6.4
	24.3	32.0	47.2	57.8
Operating income	12.0	7.8	22.5	20.5
Earnings	$6.3	$3.4	$11.6	$9.8
Transportation volumes (MMdk)	74.1	70.9	149.4	138.9
Natural gas gathering volumes (MMdk)	5.0	8.9	9.9	18.3
Customer natural gas storage balance (MMdk):				
Beginning of period	14.5	7.2	16.6	14.9
Net injection (withdrawal)	13.6	4.6	11.5	(3.1)
End of period	28.1	11.8	28.1	11.8

Three Months Ended June 30, 2016 and 2015 Pipeline and midstream earnings increased $2.9 million (87 percent) due to:

- Lower operation and maintenance expense, which includes $3.7 million (after tax) primarily due to the absence in 2016 of an impairment of coalbed natural gas gathering assets of $1.9 million (after tax), as discussed in Notes 5 and 13, as well as lower payroll and benefit-related costs
- Lower depreciation, depletion and amortization expense of $700,000 (after tax) due largely to the sale of certain non-strategic natural gas gathering assets
- Higher transportation earnings of $500,000 (after tax), primarily the result of higher volumes transported to storage offset in part by lower firm contract demand revenue
- Lower interest expense of $300,000 (after tax), primarily due to lower debt interest rates and balances
- Higher storage services earnings, primarily due to higher interruptible storage balances

Partially offsetting these increases was lower gathering and processing earnings of $2.6 million (after tax), primarily related to lower natural gas gathering volumes resulting from the sale of certain non-strategic assets, as previously discussed, and lower gathering and processing volumes at Pronghorn.

Six Months Ended June 30, 2016 and 2015 Pipeline and midstream earnings increased $1.8 million (19 percent) due to:

- Lower operation and maintenance expense, which includes $4.8 million (after tax) primarily the absence of an impairment of coalbed natural gas gathering assets in 2016 of $1.9 million (after tax), as previously discussed, lower payroll and benefit-related costs and lower maintenance materials costs
- Lower depreciation, depletion and amortization expense of $1.4 million (after tax) due to the sale of certain non-strategic assets, as previously discussed
- Lower interest expense of $400,000 (after tax) primarily the result of lower debt interest rates and balances
- Higher storage services earnings, primarily due to higher interruptible storage injections

Partially offsetting these increases was lower gathering and processing earnings of $5.5 million (after tax), primarily related to lower natural gas gathering volumes resulting from the sale of certain non-strategic assets, as previously discussed, and lower gathering and processing volumes at Pronghorn.

Construction Materials and Contracting

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(Dollars in millions)			
Operating revenues	$541.4	$496.9	$751.3	$703.5
Operating expenses:				
Operation and maintenance	456.6	433.7	661.2	634.9
Depreciation, depletion and amortization	14.8	16.2	29.9	32.7
Taxes, other than income	11.9	11.4	21.4	20.1
	483.3	461.3	712.5	687.7
Operating income	58.1	35.6	38.8	15.8
Earnings	$33.7	$20.1	$19.2	$5.5
Sales (000's):				
Aggregates (tons)	7,659	6,940	11,285	10,506
Asphalt (tons)	2,213	1,727	2,452	1,959
Ready-mixed concrete (cubic yards)	1,050	988	1,694	1,564

Three Months Ended June 30, 2016 and 2015 Construction materials and contracting earnings increased $13.6 million (67 percent) with higher earnings in all regions primarily due to:

- Higher earnings of $4.4 million (after tax) resulting from increased construction revenues and margins, largely the effect of increased construction activity
- Higher earnings of $3.7 million (after tax) resulting from higher asphalt margins, which includes lower asphalt oil costs, and higher demand-related volumes
- Higher earnings of $1.4 million (after tax) resulting from higher ready-mixed concrete margins and demand-related volumes
- Higher earnings from other product line margins

Six Months Ended June 30, 2016 and 2015 Construction materials and contracting earnings increased $13.7 million (249 percent) with higher earnings in all regions primarily due to:

- Higher earnings of $5.4 million (after tax) resulting from increased construction revenues and margins, largely the effect of increased construction activity
- Higher earnings of $4.4 million (after tax) resulting from higher asphalt margins and volumes, as previously discussed
- Higher earnings of $1.8 million (after tax) resulting from higher ready-mixed concrete margins and demand-related volumes
- Higher earnings from other product line margins
- The absence in 2016 of a MEPP withdrawal liability of $1.5 million (after tax), as discussed in Note 16

Partially offsetting these increases were unfavorable income tax changes, which includes $2.4 million primarily due to higher effective tax rates.

Construction Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions)			
Operating revenues	$286.0	$215.0	$542.0	$462.1
Operating expenses:				
Operation and maintenance	260.7	191.8	494.3	416.8
Depreciation, depletion and amortization	3.8	3.3	7.6	6.7
Taxes, other than income	9.7	7.4	20.4	17.3
	274.2	202.5	522.3	440.8
Operating income	11.8	12.5	19.7	21.3
Earnings	$7.0	$7.0	$13.0	$11.8

Three Months Ended June 30, 2016 and 2015 Construction services experienced earnings comparable to earnings a year ago due to:

- Higher inside electrical workloads and margins offset in part by lower outside workloads and margins in the Western region
- Higher industrial and inside electrical workloads and margins and higher outside workloads offset in part by lower equipment sales and rental margins in the Central region

Partially offsetting these increases was higher selling, general and administrative expense of $1.3 million (after tax), primarily higher payroll-related costs and bad debt expense.

Six Months Ended June 30, 2016 and 2015 Construction services earnings increased $1.2 million (10 percent) due to:

- Higher inside electrical workloads and margins offset in part by lower outside workloads and margins in the Western region
- Tax benefit of $1.5 million related to the disposition of a non-strategic asset
- Absence of the 2015 underperforming non-strategic asset loss of $1.4 million (after tax)

Partially offsetting these increases were:

- Lower industrial workloads and margins and lower equipment sales and rental margins offset in part by higher outside workloads and higher inside electrical workloads and margins in the Central region
- Higher selling, general and administrative expense of $1.6 million (after tax), primarily higher bad debt expense and payroll-related costs

Other

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions)			
Operating revenues	$2.1	$2.2	$4.1	$4.4
Operating expenses:				
Operation and maintenance	2.2	4.7	3.9	9.3
Depreciation, depletion and amortization	.5	.5	1.0	1.0
Taxes, other than income	—	—	.1	.1
	2.7	5.2	5.0	10.4
Operating loss	(.6)	(3.0)	(.9)	(6.0)
Loss	$(1.1)	$(4.5)	$(2.6)	$(9.4)

Included in Other are general and administrative costs and interest expense previously allocated to the exploration and production and refining businesses that do not meet the criteria for income (loss) from discontinued operations.

Three Months Ended June 30, 2016 and 2015 Other loss decreased $3.4 million, primarily the result of lower operation and maintenance expense and lower interest expense previously allocated to the exploration and production business, which have been reduced with the sale of Fidelity's marketed oil and natural gas assets.

Six Months Ended June 30, 2016 and 2015 Other loss decreased $6.8 million, primarily the result of lower operation and maintenance expense and lower interest expense previously allocated to the exploration and production business, as previously discussed.

Discontinued Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions)			
Loss from discontinued operations before intercompany eliminations, net of tax	$(285.1)	$(263.5)	$(303.3)	$(593.6)
Intercompany eliminations	9.0	.1	9.1	.2
Loss from discontinued operations, net of tax	(276.1)	(263.4)	(294.2)	(593.4)
Loss from discontinued operations attributable to noncontrolling interest	(120.7)	(7.8)	(131.7)	(11.2)
Loss from discontinued operations attributable to the Company, net of tax	$(155.4)	$(255.6)	$(162.5)	$(582.2)

Three Months Ended June 30, 2016 and 2015 The loss from discontinued operations attributable to the Company was $155.4 million compared to a loss of $255.6 million for the comparable prior period due to the absence in 2016 of a fair value impairment of the exploration and production business's assets in 2015 of $252.0 million (after tax), as discussed in Note 10.

Partially offsetting the decreased loss were:

- A fair value impairment of Dakota Prairie Refining of $156.7 million (after tax), as discussed in Note 10
- A loss in 2016 compared to income in 2015 at the exploration and production business, excluding impairments, due to the sale of the marketed oil and natural gas assets in 2015
- Higher loss attributable to the Company related to Dakota Prairie Refining largely due to the commencement of operations in May 2015, primarily higher operation and maintenance expense resulting from higher rail-related costs, costs related to the accrual of costs for RINs and higher inventory costs; and higher depreciation, depletion and amortization expense. The higher expenses were largely offset by refined product sales gross margins, which were negatively impacted by low refined product sales prices and narrow Bakken basis differentials on crude oil.

Six Months Ended June 30, 2016 and 2015 The loss from discontinued operations attributable to the Company was $162.5 million compared to a loss of $582.2 million for the comparable prior period due to:

- Absence in 2016 of a noncash write-down of oil and natural gas properties of $315.3 million (after tax), as discussed in Note 10
- Absence in 2016 of a fair value impairment of $252.0 million (after tax), as previously discussed
- Decreased loss at the exploration and production business, excluding impairments, due to the sale of the marketed oil and natural gas assets in 2015

Partially offsetting the decreased loss were:

- A fair value impairment of Dakota Prairie Refining of $156.7 million (after tax), as previously discussed
- Higher loss attributable to the Company related to Dakota Prairie Refining largely due to the commencement of operations in May 2015, primarily higher operation and maintenance expense resulting from higher rail-related costs, costs related to the accrual of costs for RINs, higher payroll-related costs and higher inventory costs; and higher depreciation, depletion and amortization expense; offset in part by refined product sales gross margins, 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		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(In millions)			
Intersegment transactions:				
Operating revenues	$8.5	$13.2	$31.9	$48.9
Purchased natural gas sold	6.6	6.5	27.6	27.5
Operation and maintenance	1.9	5.5	4.3	18.6
Income from continuing operations	—	.7	—	1.7

For more information on intersegment eliminations, see Note 15.

Prospective Information

The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for certain of the Company's businesses. Many of these highlighted points are "forward-looking statements." There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Item 1A - Risk Factors, as well as Part I, Item 1A - Risk Factors in the 2015 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.

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

Electric and natural gas distribution

- Organic growth opportunities are expected to result in substantial growth of the rate base, which at year-end was $1.8 billion. Rate base growth is projected to be approximately 7 percent compounded annually over the next five years, including plans for an approximate $1.5 billion capital investment program.
- The Company expects its customer base to grow by 1.0 percent to 2.0 percent per year.
- Investments of approximately $55 million were made in 2015 to serve growth in the electric and natural gas customer base associated with the Bakken oil development. Due to sustained lower commodity prices, investments of approximately $35 million are expected in 2016.
- In June 2016, the Company, along with a partner, began 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 $205 million, including development costs and substation upgrade costs. The project has been approved as a MISO multi-value project. More than 95 percent of the necessary easements have been secured. The Company expects the project to be completed in 2019.
- The Company is reviewing potential future generation options and is considering a large-scale resource. The integrated resource plan filed in July 2015 includes a 200 MW resource addition in the 2020 time frame. The Company will continue to refine forecasted projections and adjust the timing of the addition if necessary.
- The Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system.
- The Company is focused on organic growth, while monitoring potential merger and acquisition opportunities.
- The Company is evaluating the final Clean Power Plan rule published by the EPA in October 2015, which requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. It is unknown at this time what each state will require for emissions limits or reductions from each of the Company's owned and jointly owned fossil fuel-fired electric generating units. In February 2016, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending the outcome of legal challenges. The Company has not included capital

expenditures in 2016 through 2018 for the potential compliance requirements of the Clean Power Plan.

- Regulatory actions

Completed Cases:

Since January 1, 2015, the Company has implemented a total of $42.5 million in final rates. This includes electric rate proceedings in Montana, North Dakota, South Dakota and before the FERC, and natural gas proceedings in Montana, North Dakota, Oregon, South Dakota, Washington and Wyoming. Cases recently completed were:

On June 30, 2015, the Company filed applications with the SDPUC for electric and natural gas rate increases, as discussed in Note 17.

On December 1, 2015, the Company filed an application with the WUTC for a natural gas rate increase, as discussed in Note 17.

Pending Cases:

The Company is requesting a total of $42.8 million, which includes $33.1 million in implemented interim rates. Cases pending are:

- On September 30, 2015 and April 29, 2016, the Company filed applications with the MNPUC and OPUC, respectively, for natural gas rate increases, as discussed in Note 17.
- On October 21, 2015, the Company filed an application with the NDPSC for an update to the generation resource recovery rider and requested a renewable resource cost adjustment rider. On October 26, 2015, the Company resubmitted the application as two applications. The applications are discussed in Note 17.
- On November 25, 2015, the Company filed an application with the NDPSC for an update to its transmission cost adjustment for recovery of MISO-related charges and two transmission projects located in North Dakota, as discussed in Note 17.
- On June 1, 2016, the Company filed an application with the WUTC for an annual pipeline replacement cost recovery mechanism, as discussed in Note 17.
- On June 10, 2016, the Company filed an application with the WYPSC for an electric rate increase, as discussed in Note 17.

Expected Filings:

In the third quarter of 2016, the Company expects to file an electric rate case in North Dakota and a natural gas rate case in Idaho.

Pipeline and midstream

- The Company signed agreements to complete expansion projects, including North Badlands, Northwest North Dakota, Charbonneau and Line Section 25. The North Badlands project includes a 4-mile loop of the Garden Creek pipeline segment and other ancillary facilities, and was placed in service on August 1, 2016. The Northwest North Dakota project includes modification of existing compression, a new unit and re-cylindering, and was put into service in June 2016. The Charbonneau and Line Section 25 expansions will include a new compression station as well as other compression modifications and are expected to be in service in the second quarter of 2017.
- The Company has seen strong interruptible storage service injections through the first and second quarters of 2016 due to wider seasonal spreads and lower natural gas prices. Given the current pricing environment, the Company expects storage injections to continue, but at a slower rate than the first and second quarters of 2016.
- The Company has an agreement with an anchor shipper to construct a pipeline to connect the Demicks Lake gas processing plant in northwestern North Dakota to deliver natural gas into a new interconnect with the Northern Border Pipeline. Project costs are estimated to be $50 million to $60 million. The project is currently delayed by the plant owner.
- In June 2016, the Company launched an open season to obtain capacity commitments on a proposed approximately 38-mile pipeline with the primary purpose of delivering natural gas supply to eastern North Dakota and far western Minnesota. An open season seeking capacity commitments closed on July 15, 2016. Initial interest in the project has been promising and the Company will be working with those parties to execute binding precedent agreements over the next few weeks. The Valley Expansion Project would connect the Viking Gas Transmission Company pipeline near Felton, Minnesota, to the Company's existing pipeline near Mapleton, North Dakota. As initially designed, the pipeline will be able to transport 40 million cubic feet of natural gas per day. With minor enhancements, it will be able to transport significantly more volume if required, based on capacity requested during the open season or as needed in the future as the region's needs grow. Cost of the expansion project is estimated at $50 million. Following receipt of adequate capacity commitments and necessary permits and regulatory approvals, construction on the new pipeline could begin in early 2018 with completion expected in late 2018.
- The Company continues to target profitable growth by means of both organic growth projects in areas of existing operations and by looking for potential acquisitions that fit existing expertise and capabilities.
- The Company is focused on continually improving existing operations and accelerating growth to become the leading pipeline company and midstream provider in all areas in which it operates.

Construction materials and contracting

- Approximate work backlog at June 30, 2016, was $805 million, compared to $833 million a year ago. Private work represents 7 percent of construction backlog and public work represents 93 percent of backlog.
- Projected revenues are in the range of $1.85 billion to $1.95 billion in 2016.
- The Company anticipates margins in 2016 to be slightly higher compared to 2015 margins.
- In December 2015, Congress passed, and the president signed, a $305 billion five-year highway bill for funding of transportation infrastructure projects that are a key part of the construction materials market.

- The Company continues to pursue opportunities for expansion in energy projects, such as petrochemical and transmission. 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 1.0 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.
- Knife River is still in negotiations on the four labor contracts, as reported in Items 1 and 2 - Business Properties - General in the 2015 Annual Report.

Construction services

- Approximate work backlog at June 30, 2016, was $508 million, compared to $429 million a year ago. The backlog includes transmission, distribution, substation, industrial, petrochemical, mission critical, solar energy renewables, research and development, higher education, government, transportation, health care, hospitality, gaming, commercial, institutional and service work.
- Projected revenues are in the range of $1.0 billion to $1.1 billion in 2016.
- The Company anticipates margins in 2016 to be slightly lower compared to 2015 margins.
- The Company continues to pursue opportunities for expansion in energy projects, such as petrochemical, transmission, substations, utility services and renewables. Initiatives are aimed at capturing additional market share and expanding into new markets.
- As the eighth-largest specialty contractor, the Company continues to pursue opportunities for expansion and execute initiatives in current and new markets that align with the Company's expertise, resources and strategic growth plan.

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 assets held for sale, 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 2015 Annual Report. For more information on critical accounting policies involving significant estimates, see Part II, Item 7 in the 2015 Annual Report.

Liquidity and Capital Commitments

At June 30, 2016, the Company had cash and cash equivalents of $85.1 million and available capacity of $496.0 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 in Capital resources; and through the issuance of long-term debt.

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. Changes in cash flows for discontinued operations are related to the former exploration and production and refining businesses.

Cash flows provided by operating activities in the first six months of 2016 decreased $91.6 million from the comparable period in 2015. The decrease in cash flows provided by operating activities was largely from lower cash flows at the exploration and production and refining businesses. The decrease was also due to higher working capital requirements at the electric and natural gas distribution businesses partially offset by lower working capital requirements at the construction materials and contracting business. Partially offsetting the decrease in cash flows provided by operating activities was higher cash flows from continuing operations (excluding working capital) at the electric, natural gas distribution and construction materials and contracting businesses.

Investing activities Cash flows used in investing activities in the first six months of 2016 decreased $224.8 million from the comparable period in 2015 primarily due to lower capital expenditures largely at the exploration and production and refining businesses.

Financing activities Cash flows provided by financing activities in the first six months of 2016 decreased $215.2 million from the comparable period in 2015. The decrease in cash flows provided by financing activities was primarily due to debt repayment in connection with the sale of the refining business. The decrease was also due to higher repayment of long-term debt of $161.6 million, partially offset by higher issuance of long-term debt.

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Defined benefit pension plans

There were no material changes to the Company's qualified noncontributory defined benefit pension plans from those reported in the 2015 Annual Report. For more information, see Note 16 and Part II, Item 7 in the 2015 Annual Report.

Capital expenditures

Capital expenditures for the first six months of 2016 from continuing operations were $199.0 million ($184.0 million, net of proceeds from sale or disposition of property) and are estimated to be approximately $389.0 million for 2016 ($369.0 million, net of proceeds from sale or disposition of property). Capital expenditures for the first six months of 2016 from discontinued operations were $29.1 million, which includes the purchase of Calumet's 50 percent interest in Dakota Prairie Refining, and excludes net proceeds of $45.3 million from the sale or disposition of property.

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
- Power generation and transmission opportunities
- Environmental upgrades
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimated 2016 capital expenditures referred to previously. The Company expects the 2016 estimated capital expenditures to be funded by various sources, including internally generated funds; the Company's credit facilities, as described later; through the issuance of long-term debt; and asset sales.

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, 2016. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For more information on the covenants, certain other conditions and cross-default provisions, see Part II, Item 8 - Note 7, in the 2015 Annual Report.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at June 30, 2016:

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		$ 66.0	(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)	$ 31.3		$ —		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$650.0		$ 344.5	(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) Outstanding letter(s) of credit reduce 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. 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 3.6 times, 3.0 times and 3.1 times for the 12 months ended June 30, 2016 and 2015, and December 31, 2015, respectively.
Total equity as a percent of total capitalization was 53 percent, 54 percent and 58 percent at June 30, 2016 and 2015, and December 31, 2015, 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 agreement terminated on February 28, 2016. The common stock was offered for sale, from time to time, in accordance with the terms and conditions of the agreement. Proceeds from the shares of common stock under the agreement were used for corporate development purposes and other general corporate purposes. Under the agreement, the Company did not issue any shares of stock between January 1, 2016 and February 28, 2016. Since inception of the Equity Distribution Agreement, the Company issued a cumulative total of 4.4 million shares of stock receiving net proceeds of $144.7 million through February 28, 2016.
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.
Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the capital markets. If Centennial were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.
Prior to the maturity of the Centennial credit agreement, Centennial expects that it will negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event Centennial is unable to successfully negotiate this agreement, or in the event the fees on this facility become too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

WBI Energy Transmission, Inc. On May 17, 2016, WBI Energy Transmission entered into an amendment to its amended and restated uncommitted note purchase and private shelf agreement to increase the aggregate issuance capacity from $175.0 million to $200.0 million and extend the issuance period to May 16, 2019. WBI Energy Transmission had $100.0 million of notes outstanding at June 30, 2016, which reduced capacity under this uncommitted private shelf agreement to $100.0 million. This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

Off balance sheet arrangements

In June 2016, WBI Energy sold all of the outstanding membership interests in Dakota Prairie Refining. In connection with the sale, Centennial agreed to continue to guarantee certain debt obligations of Dakota Prairie Refining which totaled $66 million at June 30, 2016, and are expected to mature by 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining.

In March 2016, a sale agreement was signed to sell Fidelity's assets in the Paradox Basin. In connection with the sale, Centennial agreed to guarantee Fidelity's indemnity obligations associated with the Paradox assets. The guarantee was required by the buyer as a condition to the sale of the Paradox Basin assets.

In connection with the sale of the Brazilian Transmission Lines, Centennial agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who were 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.

Contractual obligations and commercial commitments

There are no material changes in the Company's contractual obligations from continuing operations relating to long-term debt, estimated interest payments, purchase commitments, asset retirement obligations, uncertain tax positions and minimum funding requirements for its defined benefit plans for 2016 from those reported in the 2015 Annual Report.

The Company's contractual obligations relating to operating leases at June 30, 2016, increased $38.8 million or 24 percent from December 31, 2015. As of June 30, 2016, the Company's contractual obligations related to operating leases aggregated $200.7 million. The scheduled amounts of redemption (for the twelve months ended June 30, of each year listed) aggregate $49.9 million in 2017; $40.6 million in 2018; $32.2 million in 2019; $22.7 million in 2020; $12.5 million in 2021; and $42.8 million thereafter.

For more information on contractual obligations and commercial commitments, see Part II, Item 7 in the 2015 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 and interest rates. The Company has policies and procedures to assist in controlling these market risks and from time to time 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 2015 Annual Report, the Consolidated Statements of Comprehensive Income and Notes 9 and 12.

Commodity price risk

Fidelity historically utilized 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.

There were no derivative agreements at June 30, 2016.

Interest rate risk

There were no material changes to interest rate risk faced by the Company from those reported in the 2015 Annual Report.

At June 30, 2016, the Company had no outstanding interest rate 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, 2016, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II -- Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 18, which is incorporated 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 2015 Annual Report other than the risk that the Company's pipeline and midstream business is dependent on factors that are subject to various external influences; the risk that the Company's operations could be adversely impacted by initiatives to reduce GHG emissions; the risk related to obligations under MEPPs; the risk related to the sale of the Company's exploration and production assets; and the risk related to the sale of Dakota Prairie Refining. These factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Economic Risks

The Company's pipeline and midstream business is dependent on factors, including commodity prices and commodity price basis differentials, that are subject to various external influences that cannot be controlled.

These factors include: fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; domestic and foreign supplies of oil, NGL and natural gas; political and economic conditions in oil producing countries; actions of the Organization of Petroleum Exporting Countries; and other risks incidental to the development and operations of oil and natural gas processing plants and pipeline systems. Continued prolonged depressed prices for oil, NGL and natural gas could impede the growth of our pipeline and midstream business, and could negatively affect the results of operations, cash flows and asset values of the Company's pipeline and midstream business.

Environmental and Regulatory Risks

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. 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 50 percent of Montana-Dakota's owned generating capacity and approximately 75 percent of the electricity it generated in 2016 was from coal-fired facilities.

On October 23, 2015, the EPA published the final Clean Power Plan rule that requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. As published, the rule requires that states must, by September 6, 2016, either submit to the EPA a request for a two-year extension to submit a final state plan, or submit a final plan demonstrating how emissions reductions will be achieved and include emission limits in the form of an annual emission cap or an emission rate that will be applied to each fossil fuel-fired electric generating facility within the state starting in 2022. Emissions limits become more stringent from 2022 to 2030, with the 2030 emission limits applying thereafter. It is unknown at this time what each state will require for emissions limits or reductions from each of Montana-Dakota's owned and jointly owned fossil fuel-fired electric generating units. Compliance costs will become clearer as final state plans are submitted to the EPA. On February 9, 2016, however, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending disposition of the applicants' petition for review in the D.C. Circuit Court and disposition of the applicants' petition for a writ of certiorari if such a writ is sought. The effective date and compliance dates in the rule are expected to be addressed in a future decision made by the United States Supreme Court.

On January 14, 2015, President Obama announced a goal to reduce methane emissions from the oil and natural gas industry by 40 percent to 45 percent below 2012 levels by 2025. On June 3, 2016, the EPA published a final rule updating new source performance standards for the oil and natural gas industry. The final rule builds on 2012 requirements to reduce volatile organic compound emissions from oil and natural gas sources by establishing requirements to reduce methane emissions from previously regulated sources, as well as adding volatile organic compound and methane requirements for sources previously not covered by the rule. The rule impacts new and modified natural gas gathering and boosting stations and transmission and storage compressor stations. WBI Energy is currently developing implementation plans for complying with the rule. In addition, on March 10, 2016, the EPA announced its plans to reduce emissions from the oil and natural gas industry by moving to regulate emissions from existing sources. The EPA began this process by issuing a draft Information Collection Request on June 3, 2016. The purpose of the Information Collection Request is to gather information on existing sources of methane emissions, technologies to reduce emissions and the costs of those technologies in the oil and natural gas sector. The information collected will be used to develop comprehensive regulations to reduce methane emissions from existing sources. It is unknown at this time how the Company will be impacted or if compliance costs will be material.

The Washington DOE proposed a rule to reduce carbon dioxide emissions in the state of Washington on January 5, 2016, and on February 26, 2016, the rule was withdrawn. On May 31, 2016, the Washington DOE issued a revised proposed rule which requires carbon dioxide emission reductions from various industries in the state, including carbon dioxide emissions resulting from the combustion of natural gas supplied to end-use customers by natural gas distribution companies, such as Cascade. In 2017, the rule would require Cascade to hold carbon dioxide emissions to a baseline, equal to the average emissions in 2012 to 2016. Beginning in 2018, annual carbon dioxide emissions would be reduced by an additional 1.7 percent of the baseline from the previous year's emissions. Washington DOE proposes compliance for natural gas suppliers to be achieved through purchasing emissions reductions from projects located within the state of Washington, including energy efficiency measures that reduce natural gas usage, or from a limited amount of out-of-state allowances. Purchasing emissions reductions and allowances will increase the operating costs for Cascade. If Cascade could not receive timely and full recovery of compliance costs from its customers, such costs could adversely impact the results of its operations.

There also may be new treaties, legislation or regulations to reduce GHG emissions that could affect the Company's 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 the Company’s utility operations do 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 and cash flows.

In addition to Montana-Dakota's electric generation operations, the Company monitors and analyzes the GHG emissions from other operations and reports as required by applicable laws and regulations. The Company will continue to monitor GHG regulations and their potential impact on 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.

Other Risks
Costs related to obligations under MEPPs could have a material negative effect on the Company's results of operations and cash flows.
Various operating subsidiaries of the Company participate in approximately 75 MEPPs for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.
The Company may be obligated to increase its contributions to underfunded plans that are classified as being in endangered, seriously endangered or critical status as defined by the Pension Protection Act of 2006. Plans classified as being in one of these statuses are required to adopt RPs or FIPs to improve their funded status through increased contributions, reduced benefits or a combination of the two. Based on available information, the Company believes that approximately 35 percent of the MEPPs to which it contributes are currently in endangered, seriously endangered or critical status.
The Company may also be required to increase its contributions to MEPPs where the other participating employers in such plans withdraw from the plan and are not able to contribute an amount sufficient to fund the unfunded liabilities associated with their participants in the plans. The amount and timing of any increase in the Company's required contributions to MEPPs may also depend upon one or more of the following factors including the outcome of collective bargaining, actions taken by trustees who manage the plans, actions taken by the plans' other participating employers, the industry for which contributions are made, future determinations that additional plans reach endangered, seriously endangered or critical status, government regulations and the actual return on assets held in the plans, among others. The Company may experience increased operating expenses as a result of the required contributions to MEPPs, which may have a material adverse effect on the Company's results of operations, financial position or cash flows.
In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan to the extent these plans are underfunded.
On September 24, 2014, JTL - Wyoming provided notice to the plan administrator of one of the MEPPs to which it is a participating employer that it was withdrawing from that plan effective October 26, 2014. The plan administrator will determine JTL - Wyoming’s withdrawal liability, which the Company currently estimates at approximately $16.4 million (approximately $9.8 million after tax). The assessed withdrawal liability for this plan may be significantly different from the current estimate. Also, this plan's administrator has alleged that JTL - Wyoming owes additional contributions for periods of time prior to its withdrawal, which could affect its final assessed withdrawal liability. JTL - Wyoming disputes the plan administrator's demand for additional contributions, and on February 23, 2016, filed a declaratory judgment action in the United States District Court for the District of Wyoming to resolve the dispute.
While the Company has completed the sale of all of Fidelity's marketed oil and natural gas assets, Fidelity is subject to potential liabilities relating to the sold assets, primarily arising from events prior to sale.
As part of the Company's corporate strategy, it sold its marketed Fidelity oil and natural gas assets and has exited that line of business. Fidelity will continue to be subject to potential liabilities, either directly or through indemnification of buyers, relating to the sold assets, primarily arising from events prior to the sale.
While the Company has completed the sale of its membership interests in Dakota Prairie Refining, the Company is subject to potential liabilities relating to the business arising from events prior to sale.
The Company is subject to potential liabilities, either directly or through indemnification, of the buyer for breach of any representations, warranties or covenants in the membership interest purchase agreement, and to Calumet for indemnification for matters identified in the purchase and sale agreement relating to the business prior to the sale.
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 5, 2016	BY:	/s/ Doran N. Schwartz
			Doran N. Schwartz
			Vice President and Chief Financial Officer
		BY:	/s/ Jason L. Vollmer
			Jason L. Vollmer
			Vice President, Chief Accounting Officer and Treasurer

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Exhibit Index

Exhibit No.	
2(a)	Membership Interest Purchase Agreement, dated as of June 24, 2016, between WBI Energy, Inc. and Tesoro Refining & Marketing Company LLC, filed as Exhibit 2.1 to Form 8-K/A dated June 24, 2016, filed on July 21, 2016*
2(b)	Purchase and Sale Agreement, dated as of June 9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and, as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P., filed as Exhibit 2.2 to Form 8-K/A dated June 24, 2016, filed on July 21, 2016*
2(c)	Amendment No. 1 to Purchase and Sale Agreement, dated as of June 9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and, as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P., filed as Exhibit 2.3 to Form 8-K/A dated June 24, 2016, filed on July 21, 2016*
+10(a)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of July 19, 2016
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, 2016, 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.

* Incorporated herein by reference as indicated.

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.