MDU RESOURCES GROUP INC
Form 10-K
February 19, 2016
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
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)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
Preferred Stock, par value $100
(Title of Class)
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o.
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No ý.
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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý
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 Act). Yes o No ý.

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2015: $3,805,857,581.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 11, 2016: 195,265,744 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's 2016 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

Definitions

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
BART	Best available retrofit technology
Bbl	Barrel
Bcf	Billion cubic feet
Bicent	Bicent Power LLC
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
Bombard Mechanical	Bombard Mechanical, LLC, an indirect wholly owned subsidiary of MDU Construction Services
BPD	Barrels per day
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
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Colorado Court of Appeals	Court of Appeals, State of Colorado
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
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
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization

EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ESA	Endangered Species Act
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

Definitions

GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
GVTC	Generation Verification Test Capacity
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LTM	LTM, Incorporated, an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand decatherms
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
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBOE	Millions of BOE
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million decatherms
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
PCBs	Polychlorinated biphenyls
Proxy Statement	Company's 2016 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act

Definitions

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
Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
Sheridan System	A separate electric system owned by Montana-Dakota
South Dakota DENR	South Dakota Department of Environment and Natural Resources
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
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
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission
ZRCs	Zonal resource credits - a MW of demand equivalent assigned to generators by MISO for meeting system reliability requirements

Part I

Forward-Looking Statements

This Form 10-K 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, and 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 Item 7 - MD&A - Prospective Information.

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. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

Items 1 and 2. Business and Properties

General

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Its principal executive offices are at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

Montana-Dakota, through the electric and natural gas distribution segments, generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Cascade distributes natural gas in Oregon and Washington. Intermountain distributes natural gas in Idaho. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings, Knife River, MDU Construction Services, Centennial Resources and Centennial Capital. WBI Holdings is comprised of the pipeline and midstream segment; Dakota Prairie Refinery, which is reflected in the refining segment; and Fidelity, the Company's exploration and production business. For more information on Dakota Prairie Refinery, see Item 8 - Note 17. Knife River is the construction materials and contracting segment, MDU Construction Services is the construction services segment, and Centennial Resources and Centennial Capital are both 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. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets. Therefore, Fidelity's results 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 Item 8 - Notes 2 and 13.

As of December 31, 2015, the Company had 8,689 employees with 149 employed at MDU Resources Group, Inc., 1,027 at Montana-Dakota, 34 at Great Plains, 317 at Cascade, 239 at Intermountain, 530 at WBI Holdings, 2,945 at Knife River and 3,448 at MDU Construction Services. The number of employees at certain Company operations fluctuates during the year depending upon the number and size of construction projects. The Company considers its relations with employees to be satisfactory.

The following information regarding the number of employees represented by labor contracts is as of December 31, 2015.

At Montana-Dakota and WBI Energy Transmission, 354 and 76 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2018, and March 31, 2018, respectively.

Part I

At Cascade, 179 employees are represented by the ICWU. The labor contract with the field operations group is effective through April 1, 2018.
At Intermountain, 126 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2016.
Knife River operates under 43 labor contracts that represent 455 of its construction materials employees. Knife River is in negotiations on four of its labor contracts.
MDU Construction Services has 155 labor contracts representing the majority of its employees.
The majority of the labor contracts contain provisions that prohibit work stoppages or strikes and provide for binding arbitration dispute resolution in the event of an extended disagreement.
The Company's principal properties, which are of varying ages and are of different construction types, are generally in good condition, are well maintained and are generally suitable and adequate for the purposes for which they are used.
The financial results and data applicable to each of the Company's business segments, as well as their financing requirements, are set forth in Item 7 - MD&A and Item 8 - Note 13 and Supplementary Financial Information.
The operations of the Company and certain of its subsidiaries are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. The Company believes that it is in substantial compliance with these regulations, except as to what may be ultimately determined with regard to items discussed in Environmental matters in Item 8 - Note 17. There are no pending CERCLA actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site and the Bremerton Gasworks Superfund Site.
The Company produces GHG emissions primarily from its fossil fuel electric generating facilities, as well as from natural gas pipeline and storage systems, operations of equipment and fleet vehicles, and refining activities. GHG emissions also result from customer use of natural gas for heating and other uses. As interest in reductions in GHG emissions has grown, the Company has developed renewable generation with lower or no GHG emissions.
Governmental legislative and regulatory initiatives regarding environmental and energy policy are continuously evolving and could negatively impact the Company's operations and financial results. Until legislation and regulation are finalized, the impact of these measures cannot be accurately predicted. The Company will continue to monitor legislative and regulatory activity related to environmental and energy policy initiatives. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description later. In addition, for a discussion of the Company's risks related to environmental laws and regulations, see Item 1A - Risk Factors.
This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q and current reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge through the Company's Web site as soon as reasonably practicable after the Company has electronically filed such reports with, or furnished such reports to, the SEC. The Company's Web site address is www.mdu.com. The information available on the Company's Web site is not part of this annual report on Form 10-K.
Electric
General Montana-Dakota provides electric service at retail, serving more than 142,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2015. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 13 electric generating facilities and three small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,100 and 5,000 miles of transmission and distribution lines, respectively, and 73 transmission and 318 distribution substations. Montana-Dakota has obtained and holds, or is in the process of renewing, valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises. At December 31, 2015, Montana-Dakota's net electric plant investment was $1.3 billion.

The percentage of Montana-Dakota's 2015 retail electric utility operating revenues by jurisdiction is as follows: North Dakota - 65 percent; Montana - 21 percent; Wyoming - 9 percent; and South Dakota - 5 percent. Retail electric rates, service, accounting and certain security issuances are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC. The interstate transmission and wholesale electric power operations of Montana-Dakota also are subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of securities, accounting and other matters.

Through MISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets for its integrated system. MISO is a regional transmission organization responsible for operational control of the transmission systems of its members. MISO provides security center operations, tariff administration and operates day-ahead and real-time energy markets, ancillary services and capacity markets. As a member of MISO, Montana-Dakota's generation is sold into the MISO energy market and its energy needs are purchased from that market.

System Supply, System Demand and Competition Through an interconnected electric system, Montana-Dakota serves markets in portions of western North Dakota, including Bismarck, Mandan, Dickinson, Williston and Watford City; eastern Montana, including Sidney, Glendive and Miles City; and northern South Dakota, including Mobridge. The maximum electric peak demand experienced to date attributable to Montana-Dakota's sales to retail customers on the interconnected system was 611,542 kW in August 2015. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the sales growth rate through 2020 will approximate three percent annually. The interconnected system consists of 12 electric generating facilities and three small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 704,143 kW and total net ZRCs of 513.2 in 2015. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet planning reserve margin requirements within MISO. For 2015, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 547.3. Montana-Dakota's planning reserve margin requirement within MISO was 547.3 for 2015. Montana-Dakota's interconnected system electric generating capability includes four steam-turbine generating units using coal for fuel, three combustion turbine peaking stations, three wind electric generating facilities, a reciprocating internal combustion engine, a heat recovery electric generating facility and three small portable diesel generators.

In December 2015, construction was completed on a wind farm consisting of 43 wind turbines totaling 107.5 MW of electric generation. On December 30, 2015, Montana-Dakota purchased the wind farm from Thunder Spirit Wind, LLC, at a total cost of approximately $214 million including purchase price, internal costs and AFUDC with approximately $55 million already funded in 2014. The project began commercial operation in the fourth quarter of 2015. The generation interconnects at Montana-Dakota's substation near Hettinger, North Dakota. Montana-Dakota completed construction and commissioning of an 18.7 MW reciprocating internal combustion engine electric generation project at the existing Lewis & Clark generating facility in Sidney, Montana in December of 2015. Additional energy will be purchased as needed, or if more economical, from the MISO market. In 2015, Montana-Dakota purchased approximately 47 percent of its net kWh needs for its interconnected system through the MISO market.

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date attributable to Montana-Dakota sales to retail customers on that system was approximately 61,501 kW in July 2012. Montana-Dakota has a power supply contract with Black Hills Power, Inc. to purchase up to 49,000 kW of capacity annually through December 31, 2016. Wygen III serves a portion of the needs of its Sheridan-area customers.

Part I

The following table sets forth details applicable to the Company's electric generating stations:

Generating Station	Type	Nameplate Rating (kW)	2015 ZRCs	(a)	2015 Net Generation (kWh in thousands)
Interconnected System:					
North Dakota:					
Coyote (b)	Steam	103,647	92.7		481,995
Heskett	Steam	86,000	87.2		500,630
Heskett	Combustion Turbine	89,038	70.8		1,211
Glen Ullin	Heat Recovery	7,500	3.4		38,248
Cedar Hills	Wind	19,500	4.5		57,147
Diesel Units	Oil	5,475	3.6		9
Thunder Spirit	Wind	107,500	(c)		11,174
South Dakota:					
Big Stone (b)	Steam	94,111	98.8		303,844
Montana:					
Lewis & Clark	Steam	44,000	52.1		222,192
Lewis & Clark	Reciprocating Internal Combustion Engine	18,700	(c)		96
Glendive	Combustion Turbine	75,522	73.2		1,212
Miles City	Combustion Turbine	23,150	21.4		443
Diamond Willow	Wind	30,000	5.5		89,144
		704,143	513.2		1,707,345
Sheridan System:					
Wyoming:					
Wygen III (b)	Steam	28,000	N/A		190,815
		732,143	513.2		1,898,160

(a) Interconnected system only. MISO requires generators to obtain their summer capability through the GVTC. The GVTC is then converted to ZRCs by applying each generator's forced outage factor against its GVTC. Wind generator's ZRCs are calculated based on a wind capacity study performed annually by MISO. ZRCs are used to meet supply obligations within MISO.
(b) Reflects Montana-Dakota's ownership interest.
(c) Pending accreditation.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland Coal Company under contracts that expire in May 2016, December 2021 and December 2017, respectively. The Coyote Station coal supply agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station or 30,000 tons per week, whichever may be the greater quantity at contracted pricing. The Heskett and Lewis & Clark coal supply agreements provide for the purchase of coal necessary to supply the coal requirements of these stations at contracted pricing. Montana-Dakota estimates the Heskett and Lewis & Clark coal requirement to be in the range of 450,000 to 550,000 tons and 250,000 to 350,000 tons per contract year, respectively.
The owners of Coyote Station, including Montana-Dakota, have a contract with Coyote Creek for coal supply to the Coyote Station beginning May 2016 until December 2040. Montana-Dakota estimates the Coyote Station coal supply agreement to be approximately 2.5 million tons per contract year. For more information, see Item 8 - Note 17.

The owners of Big Stone Station, including Montana-Dakota, have coal supply agreements, which meet a portion of the Big Stone Station's fuel requirements, for the purchase of 500,000 tons in 2016 from Peabody Coalsales, LLC and 750,000 in 2016 and 2017 from Alpha Coal Sales Co., LLC both at contracted pricing. The remainder of the Big Stone Station fuel requirements will be secured through separate future contracts.

Montana-Dakota has a coal supply agreement with Wyodak Resources Development Corp., to supply the coal requirements of Wygen III at contracted pricing through June 1, 2060. Montana-Dakota estimates the maximum annual coal consumption of the facility to be 585,000 tons.

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The average cost of coal purchased, including freight, at Montana-Dakota's electric generating stations (including the Big Stone, Coyote and Wygen III stations) was as follows:

Years ended December 31,	2015	2014	2013
Average cost of coal per MMBtu	$ 1.75	$ 1.74	$ 1.73
Average cost of coal per ton	$ 25.41	$ 25.11	$ 25.32

Montana-Dakota expects that it has secured adequate capacity available through existing baseload generating stations, renewable generation, turbine peaking stations, demand reduction programs and firm contracts to meet the peak customer demand requirements of its customers through mid-2017. Future capacity that is needed to replace contracts and meet system growth requirements is expected to be met by constructing new generation resources, or acquiring additional capacity through power purchase contracts or the MISO capacity auction. For more information regarding potential power generation projects, see Item 7 - MD&A - Prospective Information - Electric and natural gas distribution.

Montana-Dakota has major interconnections with its neighboring utilities and considers these interconnections adequate for coordinated planning, emergency assistance, exchange of capacity and energy and power supply reliability.

Montana-Dakota is subject to competition in varying degrees, in certain areas, from rural electric cooperatives, on-site generators, co-generators and municipally owned systems. In addition, competition in varying degrees exists between electricity and alternative forms of energy such as natural gas.

Regulatory Matters and Revenues Subject to Refund In North Dakota, Montana-Dakota reflects monthly increases or decreases in fuel and purchased power costs (including demand charges) and is deferring those electric fuel and purchased power costs that are greater or less than amounts presently being recovered through its existing rate schedules. In Montana, a monthly Fuel and Purchased Power Tracking Adjustment mechanism allows Montana-Dakota to reflect 90 percent of the increases or decreases in fuel and purchased power costs (including demand charges) and Montana-Dakota is deferring 90 percent of costs that are greater or less than amounts presently being recovered through its existing rate schedules. A fuel adjustment clause contained in South Dakota jurisdictional electric rate schedules allows Montana-Dakota to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota to reflect increases or decreases in purchased power costs (including demand charges but excluding increases or decreases from base coal price) related to power supply and Montana-Dakota is deferring costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments which are filed annually. For more information, see Item 8 - Note 4.

In North Dakota, Montana-Dakota recovers in rates the costs associated with environmental upgrades at Big Stone Station and Lewis & Clark Station. Montana-Dakota will maintain a tracker account until all costs are recovered or until the associated costs are reflected in base rates as a part of a general rate case.

In North Dakota, Montana-Dakota has the ability to recover the costs associated with new generation through a rider mechanism. Montana-Dakota will utilize this rider mechanism for new generation until such time as the costs and investment are included in base rates. For the Thunder Spirit Wind project, Montana-Dakota implemented a renewable resource cost adjustment rider. Montana-Dakota also has in place in North Dakota a transmission tracker to recover transmission costs from its regional transmission operator, MISO. The tracking mechanism has an annual true-up.

For more information on regulatory matters, see Item 8 - Note 16.

Environmental Matters Montana-Dakota's electric operations are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. Montana-Dakota believes it is in substantial compliance with these regulations.

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which they operate. Each of these permits has a five-year life. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. The Title V Operating Permit renewal application for Big Stone Station was submitted timely to the South Dakota DENR in November 2013. Big Stone Station continues to operate under conditions of the Title V Operating Permit issued by the South Dakota DENR in June 2009. It is expected that a final renewed permit will be issued in 2016 with the completion of the BART air quality control system. Wygen III is allowed to operate under the facility's construction permit until the Title V Operating Permit is issued by the Wyoming

Department of Environmental Quality. The Title V Operating Permit application for Wygen III was submitted timely in January 2011, with the permit expected to be issued in 2016. The Title V Operating Permit renewal application for Lewis & Clark Station was submitted timely in February 2014 to the Montana DEQ and the permit was issued July 2015. The Title V Operating Permit renewal application for Heskett Station was submitted timely in August 2014 to the North Dakota Department of Health and the permit was issued July 2015. The Title V Operating Permits for the Miles City and Glendive stations expire in August 2016, and the renewal applications are expected to be submitted to the Montana DEQ in early 2016.

State water discharge permits issued under the requirements of the Clean Water Act are maintained for power production facilities on the Yellowstone and Missouri rivers. These permits also have five-year lives. Montana-Dakota renews these permits as necessary prior to expiration. Other permits held by these facilities may include an initial siting permit, which is typically a one-time, preconstruction permit issued by the state; state permits to dispose of combustion by-products; state authorizations to withdraw water for operations; and Army Corps permits to construct water intake structures. Montana-Dakota's Army Corps permits grant one-time permission to construct and do not require renewal. Other permit terms vary and the permits are renewed as necessary.

Montana-Dakota's electric operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Montana-Dakota routinely handles PCBs from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota incurred $46.0 million of environmental capital expenditures in 2015, largely for the installation of a BART air quality control system at the Big Stone Station. Environmental capital expenditures are estimated to be $14.8 million, $4.1 million and $2.8 million in 2016, 2017 and 2018, respectively. Projects for 2016 through 2018 include sulfur-dioxide, nitrogen oxide and mercury and non-mercury metals emission control equipment installation and anticipated costs for coal ash disposal at electric generating stations. Montana-Dakota's capital and operational expenditures could also be affected in a variety of ways by future air emission regulations and coal ash management requirements, including the Clean Power Plan rule published by the EPA in October 2015. Montana-Dakota is evaluating the Clean Power Plan, 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 Montana-Dakota's owned and jointly owned fossil fuel-fired electric generating units. Compliance costs will become clearer as final state plans are completed and submitted to the EPA by September 2018. On February 9, 2016, 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. Montana-Dakota has not included estimates for capital expenditures in 2016 through 2018 for the potential compliance requirements of the Clean Power Plan.

Natural Gas Distribution

General The Company's natural gas distribution operations consist of Montana-Dakota, Great Plains, Cascade and Intermountain, which sell natural gas at retail, serving over 906,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states as of December 31, 2015, and provide natural gas transportation services to certain customers on the Company's systems. These services are provided through distribution systems aggregating approximately 19,100 miles. The natural gas distribution operations have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. These operations intend to protect their service areas and seek renewal of all expiring franchises. At December 31, 2015, the natural gas distribution operations' net natural gas distribution plant investment was $1.3 billion.

The percentage of the natural gas distribution operations' 2015 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho - 32 percent; Washington - 26 percent; North Dakota - 15 percent; Montana - 8 percent; Oregon - 8 percent; South Dakota - 6 percent; Minnesota - 3 percent; and Wyoming - 2 percent. The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of Idaho, including Boise, Nampa, Twin Falls, Pocatello and Idaho Falls; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; North Dakota, including Bismarck, Mandan, Dickinson, Wahpeton, Williston, Watford City, Minot and Jamestown; central and eastern Oregon, including Bend, Pendleton, Ontario and Baker City; western and north-central South Dakota, including Rapid City, Pierre, Spearfish and Mobridge; western, southeastern and south-central Washington, including Bellingham, Bremerton, Longview, Aberdeen, Wenatchee/Moses Lake, Mount Vernon, Tri-Cities, Walla Walla and Yakima; and northern Wyoming, including Sheridan and Lovell. These markets are highly seasonal and sales volumes depend largely on the weather, the effects of which are mitigated in certain jurisdictions by a weather normalization mechanism discussed in Regulatory Matters. In addition to the residential and commercial sales, the utilities transport natural gas for larger commercial and industrial customers who purchase their own supply of natural gas.

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Competition in varying degrees exists between natural gas and other fuels and forms of energy. The natural gas distribution operations have established various natural gas transportation service rates for their distribution businesses to retain interruptible commercial and industrial loads. These services have enhanced the natural gas distribution operations' competitive posture with alternative fuels, although certain customers have bypassed the distribution systems by directly accessing transmission pipelines within close proximity. These bypasses did not have a material effect on results of operations.

The natural gas distribution operations and various distribution transportation customers obtain their system requirements directly from producers, processors and marketers. The Company's purchased natural gas is supplied by a portfolio of contracts specifying market-based pricing and is transported under transportation agreements with WBI Energy Transmission, Northern Border Pipeline Company, Northwest Pipeline GP, Northern Natural Gas, Gas Transmission Northwest LLC, Northwestern Energy, Viking Gas Transmission Company, Westcoast Energy Inc., Ruby Pipeline LLC, Foothills Pipe Lines Ltd. and NOVA Gas Transmission Ltd. The natural gas distribution operations have contracts for storage services to provide gas supply during the winter heating season and to meet peak day demand with various storage providers, including WBI Energy Transmission, Questar Pipeline Company, Northwest Pipeline GP and Northern Natural Gas. In addition, certain of the operations have entered into natural gas supply management agreements with various parties. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements as well as changes in market price. The natural gas distribution operations believe that, based on current and projected domestic and regional supplies of natural gas and the pipeline transmission network currently available through their suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next decade.

Regulatory Matters The natural gas distribution operations' retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under- or over-recovered gas costs through rate adjustments which are filed annually. Montana-Dakota's North Dakota and South Dakota natural gas tariffs contain weather normalization mechanisms applicable to certain firm customers that adjust the distribution delivery charge revenues to reflect weather fluctuations during the November 1 through May 1 billing periods.

On December 28, 2015, the OPUC approved an extension of Cascade's decoupling mechanism until January 1, 2020, with an agreement that Cascade would initiate a review of the mechanism by September 30, 2019. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

For more information on regulatory matters, see Item 8 - Note 16.

Environmental Matters The natural gas distribution operations are subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The natural gas distribution operations believe they are in substantial compliance with those regulations.

The Company's natural gas distribution operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Certain locations of the natural gas distribution operations routinely handle PCBs from their natural gas operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required. Capital and operational expenditures for natural gas distribution operations could be affected in a variety of ways by potential new GHG legislation or regulation. In particular, such legislation or regulation would likely increase capital expenditures for energy efficiency and conservation programs and operational costs associated with GHG emissions compliance. Natural gas distribution operations expect to recover the operational and capital expenditures for GHG regulatory compliance in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

The natural gas distribution operations did not incur any material environmental expenditures in 2015. Except as to what may be ultimately determined with regard to the issues described later, the natural gas distribution operations do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2018.

Montana-Dakota has had an economic interest in four historic manufactured gas plants and Great Plains has had an economic interest in one historic manufactured gas plant within their service territories. Montana-Dakota is investigating a former manufactured gas plant in Montana and is planning an investigation of a former manufactured gas plant in North Dakota. Montana-Dakota will seek recovery in its natural gas rates charged to customers for any remediation costs incurred for these sites. None of the remaining former manufactured gas plant sites of Montana-Dakota or Great Plains are being actively investigated. Cascade has had an economic interest in nine former manufactured gas plants within its service territory. Cascade has been involved in the investigation and remediation of three manufactured gas plants in Washington and Oregon. See Item 8 - Note 17 for a further discussion of these three manufactured gas plants. 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.

Pipeline and Midstream
General WBI Energy owns and operates both regulated and nonregulated businesses. The regulated business of this segment, WBI Energy Transmission, owns and operates approximately 4,000 miles of transmission, gathering and storage lines in Montana, North Dakota, South Dakota and Wyoming. Three underground storage fields in Montana and Wyoming provide storage services to local distribution companies, producers, natural gas marketers and others, and serve to enhance system deliverability. Its system is strategically located near five natural gas producing basins, making natural gas supplies available to its transportation and storage customers. The system has 13 interconnecting points with other pipeline facilities allowing for the receipt and/or delivery of natural gas to and from other regions of the country and from Canada. Under the Natural Gas Act, as amended, WBI Energy Transmission is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters, and at December 31, 2015, its net plant investment was $363.4 million.
The nonregulated business of this segment owns and operates gathering facilities in Montana and Wyoming. In 2015, the Company sold its gathering facilities in Colorado. It also owns a 50 percent undivided interest in the Pronghorn assets located in western North Dakota, which include a natural gas processing plant, both oil and gas gathering pipelines, an oil storage terminal and an oil pipeline. In total, facilities include approximately 800 miles of operated field gathering lines, some of which interconnect with WBI Energy's regulated pipeline system. The nonregulated business provides natural gas and oil gathering services, natural gas processing and a variety of other energy-related services, including cathodic protection, water hauling, contract compression operations, measurement services, and energy efficiency product sales and installation services to large end-users.
A majority of its pipeline and midstream business is transacted in the northern Great Plains and Rocky Mountain regions of the United States.
For information regarding natural gas gathering operations litigation, see Item 8 - Note 17.
System Supply, System Demand and Competition Natural gas supplies emanate from traditional and nontraditional production activities in the region and from off-system supply sources. While certain traditional regional supply sources are in various stages of decline, incremental supply from nontraditional sources have been developed which has helped support WBI Energy Transmission's supply needs. This includes new natural gas supply associated with the continued development of the Bakken area in Montana and North Dakota. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. WBI Energy Transmission expects to facilitate the movement of these supplies by making available its transportation and storage services. WBI Energy Transmission will continue to look for opportunities to increase transportation, gathering and storage services through system expansion and/or other pipeline interconnections or enhancements that could provide substantial future benefits.
WBI Energy Transmission's underground natural gas storage facilities have a certificated storage capacity of approximately 353 Bcf, including 193 Bcf of working gas capacity, 85 Bcf of cushion gas and 75 Bcf of native gas. These storage facilities enable customers to purchase natural gas at more uniform daily volumes throughout the year and meet winter peak requirements.
WBI Energy Transmission competes with several pipelines for its customers' transportation, storage and gathering business and at times may discount rates in an effort to retain market share. However, the strategic location of its system near five natural gas producing basins and the availability of underground storage and gathering services, along with interconnections with other pipelines, serve to enhance its competitive position.
Although certain of WBI Energy Transmission's firm customers, including its largest firm customer Montana-Dakota, serve relatively secure residential and commercial end-users, they generally all have some price-sensitive end-users that could switch to alternate fuels.
WBI Energy Transmission transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for 2015 represented 43 percent of WBI Energy Transmission's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2017. In addition, Montana-Dakota has contracts with WBI Energy Transmission to provide firm storage

services to facilitate meeting Montana-Dakota's winter peak requirements expiring in July 2035.

The nonregulated business competes with several midstream companies for existing customers, the expansion of its systems and the installation of new systems. Its strong position in the fields in which it operates, its focus on customer service and the variety of services it offers, along with its interconnection with various other pipelines, serve to enhance its competitive position.

Environmental Matters The pipeline and midstream operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The Company believes it is in substantial compliance with those regulations.

Ongoing operations are subject to the Clean Air Act, the Clean Water Act, the RCRA and other state and federal regulations. Administration of many provisions of these laws has been delegated to the states where WBI Energy and its subsidiaries operate. Permit terms vary and all permits carry operational compliance conditions. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand and/or regulatory changes.

Detailed environmental assessments and/or environmental impact statements as required by the National Environmental Policy Act are included in the FERC's environmental review process for both the construction and abandonment of WBI Energy Transmission's natural gas transmission pipelines, compressor stations and storage facilities.

The pipeline and midstream operations did not incur any material environmental expenditures in 2015 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2018.

Construction Materials and Contracting

General Knife River operates construction materials and contracting businesses headquartered in Alaska, California, Hawaii, Idaho, Iowa, Minnesota, Montana, North Dakota, Oregon, Texas, Washington and Wyoming. These operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix and supply ready-mixed concrete for use in most types of construction, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Although not common to all locations, other products include the sale of cement, liquid asphalt for various commercial and roadway applications, various finished concrete products and other building materials and related contracting services.

For information regarding construction materials litigation, see Item 8 - Note 17.

The construction materials business had approximately $491 million in backlog at December 31, 2015, compared to $438 million at December 31, 2014. The Company anticipates that a significant amount of the current backlog will be completed during 2016.

Competition Knife River's construction materials products are marketed under highly competitive conditions. Price is the principal competitive force to which these products are subject, with service, quality, delivery time and proximity to the customer also being significant factors. The number and size of competitors varies in each of Knife River's principal market areas and product lines.

The demand for construction materials products is significantly influenced by the cyclical nature of the construction industry in general. In addition, construction materials activity in certain locations may be seasonal in nature due to the effects of weather. The key economic factors affecting product demand are changes in the level of local, state and federal governmental spending, general economic conditions within the market area that influence both the commercial and residential sectors, and prevailing interest rates.

Knife River is not dependent on any single customer or group of customers for sales of its products and services, the loss of which would have a material adverse effect on its construction materials businesses.

Reserve Information Aggregate reserve estimates are calculated based on the best available data. This data is collected from drill holes and other subsurface investigations, as well as investigations of surface features such as mine high walls and other exposures of the aggregate reserves. Mine plans, production history and geologic data also are utilized to estimate reserve quantities. Most acquisitions are made of mature businesses with established reserves, as distinguished from exploratory-type properties.

Estimates are based on analyses of the data described above by experienced internal mining engineers, operating personnel and geologists. Property setbacks and other regulatory restrictions and limitations are identified to determine the total area available for mining. Data described previously are used to calculate the thickness of aggregate materials to be recovered. Topography associated with alluvial sand and gravel deposits is typically flat and volumes of these materials are calculated by applying the thickness of the resource over the areas available for mining. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 1.5 tons per cubic yard in the ground is used for sand and gravel deposits.

Topography associated with the hard rock reserves is typically much more diverse. Therefore, using available data, a final topography map is created and computer software is utilized to compute the volumes between the existing and final topographies. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 2 tons per cubic yard in the ground is used for hard rock quarries.

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 955 million tons of the 1.0 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to be permitted for mining under current regulatory requirements. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining

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were calculated by dividing remaining reserves by the three-year average sales from 2013 through 2015. Actual useful lives of these reserves will be subject to, among other things, fluctuations in customer demand, customer specifications, geological conditions and changes in mining plans.

The following table sets forth details applicable to the Company's aggregate reserves under ownership or lease as of December 31, 2015, and sales for the years ended December 31, 2015, 2014 and 2013:

Production Area	Number of Sites (Crushed Stone) owned	leased	Number of Sites (Sand & Gravel) owned	leased	Tons Sold (000's) 2015	2014	2013	Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Anchorage, AK	—	—	1	—	1,837	1,665	1,074	17,315	N/A	11
Hawaii	—	6	—	—	1,892	1,840	1,672	53,992	2017-2064	30
Northern CA	—	—	9	1	1,580	1,340	1,525	52,204	2018	35
Southern CA	—	2	—	—	118	147	241	91,846	2035	Over 100
Portland, OR	1	3	5	3	3,562	3,244	3,343	225,148	2025-2055	67
Eugene, OR	3	4	4	—	819	928	825	155,566	2016-2046	Over 100
Central OR/WA/ID	1	1	5	4	1,493	1,254	1,045	113,867	2020-2077	90
Southwest OR	5	5	12	5	1,872	1,624	1,465	93,592	2017-2053	57
Central MT	—	—	1	2	1,383	1,260	1,236	26,094	2023-2027	20
Northwest MT	—	—	7	2	1,423	1,486	1,242	63,140	2016-2020	46
Wyoming	—	—	1	1	888	952	983	9,731	2019	10
Central MN	—	1	38	12	2,556	1,674	1,578	55,091	2016-2028	28
Northern MN	2	—	14	5	595	491	349	25,330	2016-2017	53
ND/SD	—	—	3	19	1,959	2,377	1,862	27,453	2016-2031	13
Texas	1	2	1	—	1,138	903	672	12,144	2022	13
Sales from other sources					3,844	4,642	5,601			
					26,959	25,827	24,713	1,022,513		

The 1.0 billion tons of estimated aggregate reserves at December 31, 2015, are comprised of 476 million tons that are owned and 547 million tons that are leased. Approximately 31 percent of the tons under lease have lease expiration dates of 20 years or more. The weighted average years remaining on all leases containing estimated probable aggregate reserves is approximately 22 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2013 through 2015 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 61 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves.

The changes in Knife River's aggregate reserves for the years ended December 31 were as follows:

	2015	2014 (000's of tons)	2013
Aggregate reserves:			
Beginning of year	1,061,156	1,083,376	1,088,236
Acquisitions	7,406	12,343	22,682
Sales volumes*	(23,115)	(21,185)	(19,112)
Other**	(22,934)	(13,378)	(8,430)
End of year	1,022,513	1,061,156	1,083,376

* Excludes sales from other sources.

** Includes property sales, revisions of previous estimates and expiring leases.

Environmental Matters Knife River's construction materials and contracting operations are subject to regulation customary for such operations, including federal, state and local environmental compliance and reclamation regulations. Except as to the issues described later, Knife River believes it is in substantial compliance with these regulations. Individual permits applicable to Knife River's various operations are managed largely by local operations, particularly as they relate to application, modification, renewal, compliance and reporting procedures.
Knife River's asphalt and ready-mixed concrete manufacturing plants and aggregate processing plants are subject to Clean Air Act and Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities also are subject to these

laws. In most of the states where Knife River operates, these regulatory programs have been delegated to state and local regulatory authorities. Knife River's facilities also are subject to the RCRA as it applies to the management of hazardous wastes and underground storage tank systems. These programs also have generally been delegated to the state and local authorities in the states where Knife River operates. Knife River's facilities must comply with requirements for managing wastes and underground storage tank systems.

Some Knife River activities are directly regulated by federal agencies. For example, certain in-water mining operations are subject to provisions of the Clean Water Act that are administered by the Army Corps. Knife River operates several such operations, including gravel bar skimming and dredging operations, and Knife River has the associated permits as required. The expiration dates of these permits vary, with five years generally being the longest term.

Knife River's operations also are occasionally subject to the ESA. For example, land use regulations often require environmental studies, including wildlife studies, before a permit may be granted for a new or expanded mining facility or an asphalt or concrete plant. If endangered species or their habitats are identified, ESA requirements for protection, mitigation or avoidance apply. Endangered species protection requirements are usually included as part of land use permit conditions. Typical conditions include avoidance, setbacks, restrictions on operations during certain times of the breeding or rearing season, and construction or purchase of mitigation habitat. Knife River's operations also are subject to state and federal cultural resources protection laws when new areas are disturbed for mining operations or processing plants. Land use permit applications generally require that areas proposed for mining or other surface disturbances be surveyed for cultural resources. If any are identified, they must be protected or managed in accordance with regulatory agency requirements.

The most comprehensive environmental permit requirements are usually associated with new mining operations, although requirements vary widely from state to state and even within states. In some areas, land use regulations and associated permitting requirements are minimal. However, some states and local jurisdictions have very demanding requirements for permitting new mines. Environmental impact reports are sometimes required before a mining permit application can even be considered for approval. These reports can take up to several years to complete. The report can include projected impacts of the proposed project on air and water quality, wildlife, noise levels, traffic, scenic vistas and other environmental factors. The reports generally include suggested actions to mitigate the projected adverse impacts.

Provisions for public hearings and public comments are usually included in land use permit application review procedures in the counties where Knife River operates. After taking into account environmental, mine plan and reclamation information provided by the permittee as well as comments from the public and other regulatory agencies, the local authority approves or denies the permit application. Denial is rare, but land use permits often include conditions that must be addressed by the permittee. Conditions may include property line setbacks, reclamation requirements, environmental monitoring and reporting, operating hour restrictions, financial guarantees for reclamation, and other requirements intended to protect the environment or address concerns submitted by the public or other regulatory agencies.

Knife River has been successful in obtaining mining and other land use permit approvals so sufficient permitted reserves are available to support its operations. For mining operations, this often requires considerable advanced planning to ensure sufficient time is available to complete the permitting process before the newly permitted aggregate reserve is needed to support Knife River's operations.

Knife River's Gascoyne surface coal mine last produced coal in 1995 but continues to be subject to reclamation requirements of the Surface Mining Control and Reclamation Act, as well as the North Dakota Surface Mining Act. Portions of the Gascoyne Mine remain under reclamation bond until the 10-year revegetation liability period has expired. A portion of the original permit has been released from bond and additional areas are currently in the process of having the bond released. Knife River's intention is to request bond release as soon as it is deemed possible.

Knife River did not incur any material environmental expenditures in 2015 and, except as to what may be ultimately determined with regard to the issues described later, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2018.

In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a commercial property site, acquired by Knife River - Northwest in 1999, and part of the Portland, Oregon, Harbor Superfund Site. For more information, see Item 8 - Note 17.

In October 2015, the Oregon DEQ issued a Notice of Civil Penalty to LTM asserting violations of Oregon water quality statues and rules at a site in Coos County. For more information, see Item 8 - Note 17.

Mine Safety The Dodd-Frank Act requires disclosure of certain mine safety information. For more information, see Item 4 - Mine Safety Disclosures.

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Construction Services

General MDU Construction Services provides utility construction services specializing in constructing and maintaining electric and communication 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. These services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

For information regarding construction services litigation, see Item 8 - Note 17.

Construction and maintenance crews are active year round. However, activity in certain locations may be seasonal in nature due to the effects of weather.

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2015, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2015, was approximately $493 million compared to $305 million at December 31, 2014. MDU Construction Services expects to complete a significant amount of this backlog during 2016. Due to the nature of its contractual arrangements, in many instances MDU Construction Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather MDU Construction Services is committed to perform these services if and to the extent requested by the customer. Therefore, there can be no assurance as to the customers' requirements during a particular period or that such estimates at any point in time are predictive of future revenues.

MDU Construction Services works with the National Electrical Contractors Association, the IBEW and other trade associations on hiring and recruiting a qualified workforce.

Competition MDU Construction Services operates in a highly competitive business environment. Most of MDU Construction Services' work is obtained on the basis of competitive bids or by negotiation of either cost-plus or fixed-price contracts. The workforce and equipment are highly mobile, providing greater flexibility in the size and location of MDU Construction Services' market area. Competition is based primarily on price and reputation for quality, safety and reliability. The size and location of the services provided, as well as the state of the economy, will be factors in the number of competitors that MDU Construction Services will encounter on any particular project. MDU Construction Services believes that the diversification of the services it provides, the markets it serves throughout the United States and the management of its workforce will enable it to effectively operate in this competitive environment.

Utilities and independent contractors represent the largest customer base for this segment. Accordingly, utility and subcontract work accounts for a significant portion of the work performed by MDU Construction Services and the amount of construction contracts is dependent to a certain extent on the level and timing of maintenance and construction programs undertaken by customers. MDU Construction Services relies on repeat customers and strives to maintain successful long-term relationships with these customers.

Environmental Matters MDU Construction Services' operations are subject to regulation customary for the industry, including federal, state and local environmental compliance. MDU Construction Services believes it is in substantial compliance with these regulations.

The nature of MDU Construction Services' operations is such that few, if any, environmental permits are required. Operational convenience supports the use of petroleum storage tanks in several locations, which are permitted under state programs authorized by the EPA. MDU Construction Services has no ongoing remediation related to releases from petroleum storage tanks. MDU Construction Services' operations are conditionally exempt small-quantity waste generators, subject to minimal regulation under the RCRA. Federal permits for specific construction and maintenance jobs that may require these permits are typically obtained by the hiring entity, and not by MDU Construction Services.

MDU Construction Services did not incur any material environmental expenditures in 2015 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2018.

Refining

General WBI Energy, in conjunction with Calumet, formed Dakota Prairie Refining, to develop, build and operate Dakota Prairie Refinery. The refinery is designed as a 20,000-barrel-per-day facility located in the Bakken region in Stark County in western North Dakota.

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Construction of the refinery was completed in March 2015 and the refinery began commercial operations in May 2015. The refinery processes Bakken crude oil into diesel, naphtha, ATBs and other by-products.
System Supply, System Demand and Competition Bakken crude oil is supplied to the refinery via a pipeline interconnect with the Belle Fourche Pipeline and a portion is trucked to the refinery from wells near the refinery. Crude oil contracts are generally secured on a month-to-month basis. Dakota Prairie Refining believes that adequate supplies of crude oil will continue to be available; however, more challenging to secure due to the slowdown in drilling activity in the Bakken region.
The refinery sells diesel fuel at the refinery rack to diesel wholesalers. Naphtha is railed to Canada and sold to third parties primarily for use as a diluent for tar sands production. ATBs are railed and sold to other facilities for further processing.
Dakota Prairie Refining's competitors include a number of large, integrated refiners with greater flexibility in responding to or absorbing market changes. Dakota Prairie Refining obtains all of its crude oil from third-party sources and competes with other purchasers in the local market area for these supplies. The availability and cost of crude oil, as well as the demand for and prices of the products the refining operations produce, are heavily influenced by global, as well as regional, supply and demand dynamics. Major competitors for the sale of Dakota Prairie Refining's refined products include other refineries both in the state and in the surrounding states that produce similar products.
Environmental Matters Refinery operations are subject to numerous federal, state and local laws regulating the discharge of substances into the environment or otherwise relating to the protection of the environment. Permits are required under these laws for the operation of refineries, pipelines and related refining operations facilities, and these permits are subject to revocation, modification and renewal. Compliance with applicable environmental laws, regulations and permits will continue to have an impact on refining operations, results of operations, and capital requirements. Dakota Prairie Refining believes that its current operations are in substantial compliance with applicable federal, state and local environmental laws, regulations and permits.
Dakota Prairie Refining's operations and many of the products it manufactures are subject to certain requirements of the Clean Air Act as well as related state and local laws and regulations. The EPA has the authority under the Clean Air Act to modify the formulation of the refined transportation fuel products Dakota Prairie Refining manufactures in order to limit the emissions associated with their final use. In addition, in 2014, the EPA published a proposed rule that proposes amendments to refinery standards already in effect: the National Emission Standards for Hazardous Air Pollutants from Petroleum. The proposed rule would also amend emission requirements under the existing Petroleum Refinery New Source Performance Standard. The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 prescribe certain percentages of renewable fuels (e.g., ethanol and biofuels) that, where required by the Renewable Fuel Standard, must be blended into the refining operations' produced diesel or that requirement may be satisfied by purchasing RINs. For more information on RINs, see Item 8 - Note 6. Dakota Prairie Refining's operations are also subject to the Clean Water Act, the Federal Safe Drinking Water Act and comparable state and local requirements. The Clean Water Act, the Federal Safe Drinking Water Act and analogous laws prohibit any discharge into surface waters, ground waters, injection wells and publicly owned treatment works except in conformance with legal authorization, such as pre-treatment permits and National Pollutant Discharge Elimination System permits, issued by federal, state and local governmental agencies. National Pollutant Discharge Elimination System permits and analogous water discharge permits are valid for a maximum of five years and must be renewed. Compliance with current and future environmental regulations is not expected to require material capital expenditures through 2018.
Discontinued Operations
General Discontinued operations includes the results of Fidelity other than certain general and administrative costs and interest expense. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. The completion of the majority of these sales occurred in the fourth quarter of 2015 and the

Company continues to market the remaining assets of Fidelity. For more information on discontinued operations, see Item 8 - Note 2 and Supplementary Financial Information.

For information regarding litigation from discontinued operations, see Item 8 - Note 17.

Item 1A. Risk Factors

The Company's business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents that it files with the SEC. The 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.

Part I

Economic Risks

The Company's pipeline and midstream and refining businesses are dependent on factors, including commodity prices and commodity price basis differentials/crack spreads, 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/crack spreads; 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, pipeline systems and the refinery. 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 and refining businesses.

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

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

The operation of Dakota Prairie Refinery may involve events that could negatively impact the Company's business, its results of operations, cash flows and asset values.

The operation of Dakota Prairie Refinery involves many risks, which may include: breakdown or failure of the equipment and systems; inability to operate within environmental permit parameters; inability to produce refined products to required specifications; inability to obtain crude oil supply; inability to effectively manage distribution channels; changes in markets and market prices for crude oil and refined products; operating cost increases; and the inability of Dakota Prairie Refinery to fund its operations from its operating cash flows, by obtaining third-party financing or through capital contributions from Calumet or WBI Energy; as well as the risk of performance below expected levels of output or efficiency. Such events, as well as continued operating losses at Dakota Prairie Refinery, could negatively impact the Company's business, its results of operations, cash flows and asset values.

Economic volatility, including volatility in North Dakota's Bakken region, affects the Company's operations, as well as the demand for its products and services and the value of its investments and investment returns including its pension and other postretirement benefit plans, and may have a negative impact on the Company's future revenues and cash flows.

The global demand and price volatility for natural resources, interest rate changes, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. Unfavorable economic conditions can negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, can negatively affect the demand for the Company's products and services, primarily at the Company's construction businesses. The level of demand for construction products and services could be adversely impacted by the economic conditions in the industries the Company serves, as well as in the economy in general. State and federal budget issues may negatively affect the funding available for infrastructure spending. The ability of the Company's electric and natural gas distribution businesses to grow service territory and customer base is affected by the economic environments of the markets served. This economic volatility could have a material adverse effect on the Company's results of operations, cash flows and asset values.

Changing market conditions could negatively affect the market value of assets held in the Company's pension and other postretirement benefit plans and may increase the amount and accelerate the timing of required funding contributions.

The Company relies on financing sources and capital markets. Access to these markets may be adversely affected by factors beyond the Company's control. If the Company is unable to obtain economic financing in the future, the Company's ability to execute its business plans, make capital expenditures or pursue acquisitions that the Company may otherwise rely on for future growth could be impaired. As a result, the market value of the Company's common stock may be adversely affected. If the Company issues a substantial amount of common stock it could have a dilutive effect on its existing shareholders.

The Company relies on access to short-term borrowings, including the issuance of commercial paper, long-term capital markets and asset sales as sources of liquidity for capital requirements not satisfied by its cash flow from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans may be adversely affected. Market disruptions or a downgrade of the

Part I

Company's credit ratings may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:
- A severe prolonged economic downturn
- The bankruptcy of unrelated industry leaders in the same line of business
- Deterioration in capital market conditions
- Turmoil in the financial services industry
- Volatility in commodity prices
- Terrorist attacks
- Cyber attacks

Economic turmoil, market disruptions and volatility in the securities trading markets, as well as other factors including changes in the Company's results of operations, financial position and prospects, may adversely affect the market price of the Company's common stock.

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 issuance of a substantial amount of the Company's common stock, whether sold pursuant to the registration statement, issued in connection with an acquisition or otherwise, or the perception that such an issuance could occur, may adversely affect the market price of the Company's common stock.

The Company is exposed to credit risk and the risk of loss resulting from the nonpayment and/or nonperformance by the Company's customers and counterparties.

If the Company's customers or counterparties were to experience financial difficulties or file for bankruptcy, the Company could experience difficulty in collecting receivables. The nonpayment and/or nonperformance by the Company's customers and counterparties could have a negative impact on the Company's results of operations and cash flows.

The backlogs at the Company's construction materials and contracting and construction services businesses are subject to delay or cancellation and may not be realized.

Backlog consists of the uncompleted portion of services to be performed under job-specific contracts. Contracts are subject to delay, default or cancellation and the contracts in the Company's backlog are subject to changes in the scope of services to be provided as well as adjustments to the costs relating to the applicable contracts. Backlog may also be affected by project delays or cancellations resulting from weather conditions, external market factors and economic factors beyond the Company's control. Accordingly, there is no assurance that backlog will be realized.

Environmental and Regulatory Risks

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

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

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

On April 17, 2015, the EPA published a final rule, under the RCRA, for coal combustion residuals that regulates coal ash as a solid waste and not a hazardous waste. The rule requires ground water and location restriction evaluations be conducted by October 2017 at ash impoundments and landfills not located at coal mines. In 2015, one ash impoundment at Lewis & Clark Station was replaced with a new concrete basin. Additional site and groundwater analyses may identify the need to upgrade or close additional impoundments or the Company may need to install replacement ash management systems. The cost of replacement ash impoundments or landfills may be material. If these costs are not fully recoverable from customers, they could have a material adverse effect on the Company's results of operations and cash flows.

On August 15, 2014, the EPA published a final rule under Section 316(b) of the Clean Water Act, establishing requirements for water intake structures at existing steam electric generating facilities. The purpose of the rule is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures. The majority of the Company's electric generating facilities are either not subject to the rule or have completed studies that project compliance expenditures are not material. The Lewis & Clark Station will complete a study that will be submitted to the Montana DEQ by July 31, 2019, to be used in determining any required controls. It is unknown at this time what controls may be required or if compliance costs will be material. The installation schedule for any required controls would be established with the permitting agency after the study is completed.

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

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. On October 23, 2015, the EPA published the final rule establishing carbon dioxide emission limits for new, reconstructed and modified coal-fired steam electric generating units. In this same rule, the EPA established carbon dioxide emission limits for new and reconstructed base load and non-base load stationary combustion turbines. At this time, the EPA has determined not to establish emission limits for modified stationary combustion turbines and has withdrawn the proposed rule emission standards for modified stationary combustion turbines. New coal-fired generating units must comply with an emission standard of 1,400 pounds of carbon dioxide per MW hour gross, equivalent to a super critical pulverized coal unit capturing about 20 percent of its carbon dioxide emissions. Unless carbon capture and storage technology becomes available and cost effective, no new coal-fired electric generating facilities are projected to be constructed. Limits for reconstructed and modified coal-fired generating units may preclude reconstruction or modification depending on the facility. New and reconstructed base load stationary natural gas-fired combustion turbines must comply with an emission standard of 1,000 pounds of carbon dioxide per MW hour gross which should be achievable, but could limit operating at higher load levels, depending on the unit. For newly constructed and reconstructed non-base load (peaking) natural gas-fired stationary combustion turbines, the EPA has established a heat input-based emission standard of 120 pounds of carbon dioxide per MMBtu.

On October 23, 2015, the EPA published the final Clean Power Plan rule which requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. By September 6, 2016, states must either submit to the EPA a request for an extension to submit a final state plan by September 6, 2018, or submit a final plan. The state plan must demonstrate 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 individual fossil fuel-fired electric generating facility 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 completed and submitted to the EPA by September 6, 2018. On February 9, 2016, 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 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 90 percent of the electricity it generated in 2015 was from coal-fired facilities.

On January 14, 2015, President Obama announced a goal to reduce methane emissions from the oil and natural gas industry by 40 to 45 percent below 2012 levels by 2025. On September 18, 2015, the EPA published a proposed rule on standards for methane and GHG emissions from new and modified sources within the oil and natural gas industry, with a final rule expected in 2016. The rule, as proposed, would require emission reductions and work practices for sources such as gathering and boosting stations, and transmission and storage compressor stations. The president will continue to evaluate further methods of methane reduction including additional leak detection controls and emission reporting, enhanced venting and flaring requirements for sources on public lands, and upgrades to existing natural gas transmission and distribution infrastructure. It is unknown at this time how the Company will be impacted or if compliance costs will be material.

On January 6, 2016, the Washington DOE issued the proposed Clean Air Rule, a rule requiring reductions of carbon dioxide emissions from various industries, including carbon dioxide emissions resulting from the combustion of natural gas supplied to end-use customers by natural gas distribution companies, such as Cascade. The rule requires reductions in carbon dioxide emissions resulting from the combustion of natural gas Cascade supplies to the majority of its customers. In 2017, the rule requires 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 one and two-thirds percent of the baseline from the previous year's emissions. Washington DOE proposes compliance to be achieved through emissions credit purchases using existing trading markets or by funding end-use energy efficiency projects that would reduce natural gas usage, increasing 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 Montana-Dakota's electric utility operations by requiring additional energy conservation efforts or renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs. If Montana-Dakota does not receive timely and full recovery of GHG emission compliance costs from its customers, then such costs could adversely impact the results of its operations.

In addition to Montana-Dakota's electric generation operations, the GHG emissions from the Company's other operations are monitored, analyzed and reported as required by applicable laws and regulations. The Company monitors GHG regulations and the potential for GHG regulations to impact operations.

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

The Company is subject to government regulations that may delay and/or have a negative impact on its business and its results of operations and cash flows. Statutory and regulatory requirements also may limit another party's ability to acquire the Company or impose conditions on an acquisition of or by the Company.

The Company is subject to regulation or governmental actions by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return and recovery of investment and cost, financing, rate structures, health care coverage and cost, taxes, franchises and recovery of purchased power and purchased gas costs. These governmental regulations significantly influence the Company's operating environment and may affect its ability to recover costs from its customers. The Company is unable to predict the impact on operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on the Company's results of operations and cash flows. Approval from a number of federal and state regulatory agencies would need to be obtained by any potential acquirer of the Company as well as for acquisitions by the Company. The approval process could be lengthy and the outcome uncertain.

Other Risks

Weather conditions can adversely affect the Company's operations, and revenues and cash flows.

The Company's results of operations can be affected by changes in the weather. Weather conditions influence the demand for electricity and natural gas, affect the price of energy commodities, affect the ability to perform services at the construction materials and contracting and construction services businesses and affect ongoing operation and maintenance and construction activities for the pipeline and midstream and refining businesses. In addition, severe weather can be destructive, causing outages, and/or property damage, which could require additional costs to be incurred. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial position and cash flows.

Competition exists in all of the Company's businesses.

All of the Company's businesses are subject to competition. Construction services' competition is based primarily on price and reputation for quality, safety and reliability. Construction materials products are marketed under highly competitive conditions and are subject to such competitive forces as price, service, delivery time and proximity to the customer. The electric utility and natural gas industries also are experiencing increased competitive pressures as a result of consumer demands, technological advances and other factors. The pipeline and midstream business competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. The refining business competes with larger and more diverse refineries that may be better positioned to withstand volatile industry and pricing conditions. Competition could negatively affect the Company's results of operations, financial position and cash flows.

The Company could be subject to limitations on its ability to pay dividends.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on its common stock. Regulatory, contractual and legal limitations, as well as capital requirements and the Company's financial performance or cash flows, could limit the earnings of the Company's divisions and subsidiaries which, in turn, could restrict the Company's ability to pay dividends on its common stock and adversely affect the Company's stock price.

Cost increases 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 85 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 40 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, Knife River 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 Knife River’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.

The Company's operations may be negatively impacted by cyber attacks or acts of terrorism.

The Company operates in industries that require continual operation of sophisticated information technology systems and network infrastructure. While the Company has developed procedures and processes that are designed to strengthen and protect these systems, they may be vulnerable to failures or unauthorized access due to hacking, theft, sabotage, viruses, acts of terrorism, acts of war or other causes. If the technology systems were to fail or be breached and these systems were not recovered in a timely manner, the Company's operational systems and infrastructure, such as the Company's electric generation, transmission and distribution facilities and its oil and natural gas processing facilities, storage and pipeline systems, may be unable to fulfill critical business functions, including an inability to produce or distribute some part of our energy services and other products and the provision of service to customers. Such disruption could result in decreased revenues and/or significant remediation costs which could have a material adverse effect on the Company's results of operations, financial position and cash flows. Additionally, because generation, transmission systems and gas pipelines are part of an interconnected system with other operators, a disruption elsewhere in the system could negatively impact the Company's business.

The Company's business requires access to sensitive customer, employee, shareholder and Company data in the ordinary course of business. Despite the Company's implementation of security measures, a failure or breach of a security system could compromise sensitive and confidential information and data. Such an event could result in negative publicity and reputational harm, remediation costs and possible legal claims and fines which could adversely affect the Company's financial results, notwithstanding the purchase of cyber risk insurance. The Company's third-party service providers that perform critical business functions or have access to sensitive and confidential information and data may also be vulnerable to security breaches and other risks that could have an adverse effect on the Company.

While the Company has completed the sale of the majority of Fidelity's assets and is currently marketing the remaining assets of Fidelity, there is no assurance that a sale of the remaining marketed assets will be successful, and Fidelity may continue to be subject to potential liabilities relating to the sold assets arising from events prior to sale.

As part of the Company's corporate strategy, it sold the majority of its Fidelity assets, and is currently marketing the remaining assets and will exit that line of business. Such a disposition of the remaining assets is subject to various risks, including: the purchase and sale agreements may be terminated prior to closing as a result of the due diligence process or due to inability of the purchasers to obtain financing; suitable purchasers may not be available or willing to purchase the remaining assets on terms and conditions acceptable to the

Company; the agreements pursuant to which the Company divests the assets may contain continuing indemnification obligations; the Company may incur costs in connection with the marketing and sale of the assets; there could be tax consequences dependent on the nature of the sale; and the Company may be required to record additional fair value impairment charges that could have an adverse effect on the Company's financial condition. Fidelity will also continue to be subject to potential liabilities, either directly or through indemnification of buyers, for potential liabilities relating to the sold assets arising from events prior to sale.

Other factors that could impact the Company's businesses.

The following are other factors that should be considered for a better understanding of the financial condition of the Company. These other factors may impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities
- Changes in operation, performance and construction of plant facilities or other assets
- Changes in present or prospective generation
- The ability to obtain adequate and timely cost recovery for the Company's regulated operations through regulatory proceedings
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for, available supplies of, and/or costs of, energy- and construction-related products and services
- The cyclical nature of large construction projects at certain operations
- Changes in tax rates or policies
- Unanticipated project delays or changes in project costs, including related energy costs
- Unanticipated changes in operating expenses or capital expenditures
- Labor negotiations or disputes
- Inability of contract counterparties to meet their contractual obligations
- Changes in accounting principles and/or the application of such principles to the Company
- Changes in technology
- Changes in legal or regulatory proceedings
- The ability to effectively integrate the operations and the internal controls of acquired companies
- The ability to attract and retain skilled labor and key personnel
- Increases in employee and retiree benefit costs and funding requirements

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings, see Item 8 - Note 17, which is incorporated herein by reference.

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-K, which is incorporated herein by reference.

Part II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The Company's common stock is listed on the New York Stock Exchange under the symbol "MDU." The price range of the Company's common stock as reported by The Wall Street Journal composite tape during 2015 and 2014 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2015			
First quarter	$24.51	$20.01	$.1825
Second quarter	23.12	19.22	.1825
Third quarter	19.73	16.15	.1825
Fourth quarter	19.66	16.26	.1875
			$.7350
2014			
First quarter	$35.10	$29.62	$.1775
Second quarter	36.05	32.45	.1775
Third quarter	35.41	27.35	.1775
Fourth quarter	28.51	21.33	.1825
			$.7150

As of December 31, 2015, the Company's common stock was held by approximately 12,900 stockholders of record.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends, see Item 8 - Note 10.

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2015	—			
November 1 through November 30, 2015	54,351	$18.21		
December 1 through December 31, 2015	3,830	16.97		
Total	58,181			

(1) Represents shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors and for those directors who elected to receive additional shares of common stock in lieu of a portion of their cash retainer.

(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to purchase equity securities.

Part II

Item 6. Selected Financial Data

	2015	2014	2013	2012	2011	2010
Selected Financial Data						
Operating revenues (000's):						
Electric	$280,615	$277,874	$257,260	$236,895	$225,468	$211,544
Natural gas distribution	817,419	921,986	851,945	754,848	907,400	892,708
Pipeline and midstream	156,236	157,365	144,571	142,610	152,972	175,961
Construction materials and contracting	1,904,282	1,765,330	1,712,137	1,617,425	1,510,010	1,445,148
Construction services	926,427	1,119,529	1,039,839	938,558	854,389	789,100
Refining	178,262	—	—	—	—	—
Other	9,191	9,364	9,620	10,370	11,446	7,727
Intersegment eliminations	(80,883)	(136,632)	(95,201)	(74,595)	(68,482)	(49,125)
	$4,191,549	$4,114,816	$3,920,171	$3,626,111	$3,593,203	$3,473,063
Operating income (loss) (000's):						
Electric	$57,955	$61,331	$54,274	$49,852	$49,096	$48,296
Natural gas distribution	53,810	65,633	78,829	67,579	82,856	75,697
Pipeline and midstream	29,988	46,713	20,896	49,139	45,365	46,310
Construction materials and contracting	146,026	86,462	93,629	57,864	51,092	63,045
Construction services	43,376	82,309	85,246	66,531	39,144	33,352
Refining	(68,860)	(9,097)	(850)	—	—	—
Other	(5,700)	(4,028)	(4,146)	(5,325)	(7,079)	(10,854)
Intersegment eliminations	(2,462)	(9,900)	(7,176)	—	—	—
	$254,133	$319,423	$320,702	$285,640	$260,474	$255,846
Earnings (loss) on common stock (000's):						
Electric	$35,914	$36,731	$34,837	$30,634	$29,258	$28,908
Natural gas distribution	23,607	30,484	37,656	29,409	38,398	36,944
Pipeline and midstream	13,250	24,666	7,701	26,588	23,082	23,208
Construction materials and contracting	89,096	51,510	50,946	32,420	26,430	29,609
Construction services	23,762	54,432	52,213	38,429	21,627	17,982
Refining	(22,457)	(2,038)	(72)	—	—	—
Other	(12,376)	(7,317)	(10,605)	(7,209)	(5,918)	8,508
Intersegment eliminations	(1,531)	(6,095)	(4,307)	—	—	—
Earnings on common stock before income (loss) from discontinued operations	149,265	182,373	168,369	150,271	132,877	145,159
Income (loss) from discontinued operations, net of tax*	(772,385)	115,175	109,879	(151,710)	79,464	94,815
	$(623,120)	$297,548	$278,248	$(1,439)	$212,341	$239,974
Earnings (loss) per common share before discontinued operations - diluted	$.77	$.95	$.89	$.80	$.70	$.77
Discontinued operations, net of tax	(3.97)	.60	.58	(.81)	.42	.50

	$(3.20)	$1.55	$1.47	$(.01)	$1.12	$1.27
Common Stock Statistics						
Weighted average common shares outstanding -diluted (000's)	194,986	192,587	189,693	188,826	188,905	188,229
Dividends declared per common share	$.7350	$.7150	$.6950	$.6750	$.6550	$.6350
Book value per common share	$12.83	$16.66	$15.01	$13.95	$14.62	$14.22
Market price per common share (year end)	$18.32	$23.50	$30.55	$21.24	$21.46	$20.27
Market price ratios:						
Dividend payout**	95%	75%	78%	84%	94%	82%
Yield	4.1%	3.1%	2.3%	3.2%	3.1%	3.2%
Market value as a percent of book value	142.8%	141.1%	203.5%	152.3%	146.8%	142.5%

* Reflects oil and natural gas properties noncash write-downs of $315.3 million (after tax) and $246.8 million (after tax) in 2015 and 2012, respectively, and fair value impairments of assets held for sale of $475.4 million (after tax) in 2015.

** Based on continuing operations.

Part II

Item 6. Selected Financial Data (continued)

	2015	2014	2013	2012	2011	2010
General						
Total assets (000's)	$6,627,608	$7,832,408	$7,073,447	$6,708,666	$6,583,597	$6,310,976
Total long-term debt (000's)	$1,871,232	$2,093,830	$1,853,112	$1,743,000	$1,422,207	$1,503,813
Capitalization ratios:						
Common equity	57 %	61 %	60 %	60 %	66 %	64 %
Total debt	43	39	40	40	34	36
	100 %	100 %	100 %	100 %	100 %	100 %
Electric						
Retail sales (thousand kWh)	3,316,017	3,308,358	3,173,086	2,996,528	2,878,852	2,785,710
Electric system summer and firm purchase contract ZRCs (Interconnected system)	547.3	584.0	583.5	552.8	572.8	553.3
Electric system peak demand obligation, including firm purchase contracts, planning reserve margin requirement (Interconnected system)	547.3	522.4	508.3	550.7	524.2	529.5
Demand peak - kW (Interconnected system)	611,542	582,083	573,587	573,587	535,761	525,643
Electricity produced (thousand kWh)	1,898,160	2,519,938	2,430,001	2,299,686	2,488,337	2,472,288
Electricity purchased (thousand kWh)	1,658,002	1,010,422	971,261	870,516	645,567	521,156
Average cost of fuel and purchased power per kWh	$.024	$.025	$.025	$.023	$.021	$.021
Natural Gas Distribution						
Sales (Mdk)	95,559	104,297	108,260	93,810	103,237	95,480
Transportation (Mdk)	154,225	145,941	149,490	132,010	124,227	135,823
Degree days (% of normal)						
Montana-Dakota/Great Plains	88 %	103 %	105 %	84 %	101 %	98 %
Cascade	83 %	89 %	98 %	96 %	103 %	96 %
Intermountain	89 %	95 %	110 %	91 %	107 %	100 %
Pipeline and Midstream						
Transportation (Mdk)	290,494	233,483	178,598	137,720	113,217	140,528
Gathering (Mdk)	33,441	38,372	40,737	47,084	66,500	77,154
Customer natural gas storage balance (Mdk)	16,600	14,885	26,693	43,731	36,021	58,784
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	26,959	25,827	24,713	23,285	24,736	23,349
Asphalt (tons)	6,705	6,070	6,228	5,988	6,709	6,279
Ready-mixed concrete (cubic yards)	3,592	3,460	3,223	3,157	2,864	2,764
Aggregate reserves (000's tons)	1,022,513	1,061,156	1,083,376	1,088,236	1,088,833	1,107,396

Refining						
Refined product sales (MBbls)						
Diesel fuel	1,072	*	*	*	*	*
Naphtha	996	*	*	*	*	*
ATBs and other	884	*	*	*	*	*
Total refined product sales	2,952	*	*	*	*	*

*Dakota Prairie Refinery began commercial operation in 2015.

Part II

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
Overview
The Company's strategy is to apply its expertise in energy and transportation infrastructure industries to increase market share, increase profitability and enhance shareholder value through:
- Organic growth as well as a continued disciplined approach to the acquisition of well-managed companies and properties
- The elimination of system-wide cost redundancies through increased focus on integration of operations and standardization and consolidation of various support services and functions across companies within the organization
- The development of projects that are accretive to earnings per share and return on invested capital
- 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 Item 8 - Note 13.
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.
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 northern Rockies base. Incremental and new growth opportunities include: access to new energy sources for storage, gathering and transportation services; expansion of existing gathering and transmission facilities; incremental expansion of 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; tight 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.

Part II

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; continue growth 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.

Refining

Strategy Utilize Dakota Prairie Refinery's prime location in North Dakota's Bakken region to access crude oil supplies to safely and efficiently produce into refined products. Pursue operational effectiveness to maximize returns and cash flows through efforts such as marketing, cost reductions and refinery performance improvements. Additional opportunities exist in debottlenecking the plant which could increase production volumes.

Challenges Challenges for this market include the narrowing of the differential between the Company's actual crude oil price and West Texas Intermediate crude oil prices; availability, cost and price volatility of crude oil and refined products; narrowing crack spreads for refined products including diesel, naphtha and ATBs; changes in overall demand for refined products; environmental and regulatory requirements; the potential for increasing price volatility for RINs and competition from other refineries.

For more information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see Item 1A - Risk Factors. For more information on key growth strategies, projections and certain assumptions, see Prospective Information. For information pertinent to various commitments and contingencies, see Item 8 - Notes to Consolidated Financial Statements.

Earnings Overview

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

Years ended December 31,	2015	2014	2013
	(Dollars in millions, where applicable)		
Electric	$35.9	$36.7	$34.8
Natural gas distribution	23.6	30.5	37.7
Pipeline and midstream	13.3	24.7	7.7
Construction materials and contracting	89.1	51.5	50.9
Construction services	23.8	54.5	52.2
Refining	(22.5)	(2.1)	(.1)
Other	(12.4)	(7.2)	(10.6)
Intersegment eliminations	(1.5)	(6.2)	(4.3)
Earnings before discontinued operations	149.3	182.4	168.3
Income (loss) from discontinued operations, net of tax	(772.4)	115.1	109.9
Earnings (loss) on common stock	$(623.1)	$297.5	$278.2
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	$.77	$.95	$.89
Discontinued operations, net of tax	(3.97)	.60	.58
Earnings (loss) per common share - basic	$(3.20)	$1.55	$1.47

Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	$.77	$.95	$.89
Discontinued operations, net of tax	(3.97)	.60	.58
Earnings (loss) per common share - diluted	$(3.20)	$1.55	$1.47

Part II

2015 compared to 2014 The Company recognized a consolidated loss of $623.1 million in 2015, compared to consolidated earnings of $297.5 million in 2014. This decrease was due to:

- Discontinued operations which had a fair value impairment of the Company's assets held for sale of $475.4 million (after tax); a $315.3 million after-tax noncash write-down of oil and natural gas properties; lower average realized commodity prices, excluding gain/loss on commodity derivatives; and decreased oil production; partially offset by lower depreciation, depletion and amortization expense and lease operating expense
- Lower workloads and margins in the Western region and lower equipment rental sales and margins at the construction services business
- Higher operation and maintenance, largely due to higher rail-related and contract services costs with commencement of operations of Dakota Prairie Refinery occurring in May 2015
- Impairments of natural gas gathering assets of $10.6 million (after tax) at the pipeline and midstream business
- Higher depreciation, depletion and amortization expense due to plant additions and lower natural gas sales volumes offset in part by natural gas retail rate increases at the natural gas distribution business

Partially offsetting these decreases were higher earnings on all product lines at the construction materials and contracting business.

2014 compared to 2013 Consolidated earnings for 2014 increased $19.3 million from the prior year. This increase was due to:

- The absence of the 2013 impairment of coalbed natural gas gathering assets of $9.0 million (after tax), as discussed in Item 8 - Note 1, as well as higher earnings due to increased transportation rates and higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets; partially offset by lower storage services earnings at the pipeline and midstream business
- Other earnings increased resulting from favorable income tax changes, due to the resolution of certain tax matters and higher income tax benefits

Partially offsetting these increases were higher operation and maintenance expense, higher depreciation, depletion and amortization expense and the absence of the 2013 $2.8 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business; partially offset by higher other income and natural gas retail sales margins at the natural gas distribution business.

Financial and Operating Data

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

Electric

Years ended December 31,	2015	2014	2013
	(Dollars in millions, where applicable)		
Operating revenues	$280.6	$277.9	$257.3
Operating expenses:			
Fuel and purchased power	86.2	89.3	83.5
Operation and maintenance	87.7	81.1	76.5
Depreciation, depletion and amortization	37.6	35.0	32.8
Taxes, other than income	11.1	11.1	10.2
	222.6	216.5	203.0
Operating income	58.0	61.4	54.3
Earnings	$35.9	$36.7	$34.8
Retail sales (million kWh)	3,316.0	3,308.4	3,173.1
Average cost of fuel and purchased power per kWh	$.024	$.025	$.025

2015 compared to 2014 Electric earnings decreased $800,000 (2 percent) compared to the prior year due to:

- Higher operation and maintenance expense, which includes $4.3 million (after tax) largely related to higher contract services, primarily related to a planned outage at an electric generation station, and higher payroll and benefit-related costs

- Higher depreciation, depletion and amortization expense of $1.6 million (after tax) due to increased property, plant and equipment balances
- Higher net interest expense, which includes $1.1 million (after tax) due to higher long-term debt

Partially offsetting these decreases were:

- Increased electric retail sales margins, primarily due to rate recovery of new generation

- Higher other income, which includes $3.5 million (after tax) primarily related to allowance for funds used during construction

2014 compared to 2013 Electric earnings increased $1.9 million (5 percent) compared to the prior year due to increased electric retail sales margins, primarily due to rate recovery on electric environmental upgrades and increased electric sales volumes of 4 percent to all customer classes, due to customer growth.

Partially offsetting the increase were:

- Higher operation and maintenance expense, which includes $3.5 million (after tax) largely related to higher benefit-related costs and increased contract services
- Higher net interest expense, which includes $1.8 million (after tax) due to higher long-term debt
- Higher depreciation, depletion and amortization expense of $1.4 million (after tax) due to increased property, plant and equipment balances

Natural Gas Distribution

Years ended December 31,	2015	2014	2013
	(Dollars in millions, where applicable)		
Operating revenues	$817.4	$922.0	$851.9
Operating expenses:			
Purchased natural gas sold	499.0	603.2	534.8
Operation and maintenance	153.5	150.2	142.3
Depreciation, depletion and amortization	64.8	54.7	50.0
Taxes, other than income	46.3	48.3	46.0
	763.6	856.4	773.1
Operating income	53.8	65.6	78.8
Earnings	$23.6	$30.5	$37.7
Volumes (MMdk):			
Sales	95.6	104.3	108.3
Transportation	154.2	145.9	149.5
Total throughput	249.8	250.2	257.8
Degree days (% of normal)*			
Montana-Dakota/Great Plains	88%	103%	105%
Cascade	83%	89%	98%
Intermountain	89%	95%	110%
Average cost of natural gas, including transportation, per dk	$5.22	$5.78	$4.94

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

2015 compared to 2014 The natural gas distribution business experienced a decrease in earnings of $6.9 million (23 percent) compared to the prior year due to:

- Higher depreciation, depletion and amortization expense of $6.3 million (after tax), largely resulting from increased property, plant and equipment balances
- Lower natural gas sales margins, primarily lower retail sales volumes of 8 percent to all customer classes due to warmer weather than the prior year, partially offset by approved rate increases effective in 2015 and increased transportation volumes

The pass-through of lower natural gas prices is reflected in the decrease in both sales revenue and purchased natural gas sold in 2015.

2014 compared to 2013 The natural gas distribution business experienced a decrease in earnings of $7.2 million (19 percent) compared to the prior year due to:

- Higher operation and maintenance expense, which includes $4.8 million (after tax) largely related to higher payroll and benefits-related costs

- Higher depreciation, depletion and amortization expense of $2.9 million (after tax), primarily resulting from increased property, plant and equipment balances
- The absence of the 2013 $2.8 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business

Part II

These decreases were partially offset by:

- Higher other income, which includes $2.1 million (after tax) largely related to allowance for funds used during construction
- Higher natural gas retail sales margins, primarily resulting from approved rate increases effective in late 2013, largely offset by lower sales volumes of 4 percent ($4.3 million after tax) in certain jurisdictions due to warmer weather than the prior year

Pipeline and Midstream

Years ended December 31,	2015	2014	2013
	(Dollars in millions)		
Operating revenues	$156.2	$157.4	$144.6
Operating expenses:			
Purchased natural gas sold	1.2	—	—
Operation and maintenance*	84.8	68.1	81.0
Depreciation, depletion and amortization	28.0	29.8	29.1
Taxes, other than income	12.2	12.8	13.6
	126.2	110.7	123.7
Operating income	30.0	46.7	20.9
Earnings*	$13.3	$24.7	$7.7
Transportation volumes (MMdk)	290.5	233.5	178.6
Natural gas gathering volumes (MMdk)	33.4	38.4	40.7
Customer natural gas storage balance (MMdk):			
Beginning of period	14.9	26.7	43.7
Net injection (withdrawal)	1.7	(11.8)	(17.0)
End of period	16.6	14.9	26.7

* Reflects impairments of natural gas gathering assets of $17.1 million ($10.6 million after tax) in 2015 and coalbed natural gas gathering assets of $14.5 million ($9.0 million after tax) in 2013, as discussed in Item 8 - Note 1; as well as a net benefit of $2.5 million ($1.5 million after tax) in 2013 related to the natural gas gathering operations litigation, largely reflected in operation and maintenance expense, as discussed in Item 8 - Note 17.

2015 compared to 2014 Pipeline and midstream earnings decreased $11.4 million (46 percent) largely due to:

- Impairment of natural gas gathering assets of $10.6 million (after tax) included in operation and maintenance expense, as discussed in Item 8 - Note 1
- Lower gathering and processing earnings of $5.2 million (after tax), primarily lower processing prices and natural gas gathering volumes
- Lower storage services earnings, primarily due to lower interruptible storage withdrawal volumes and lower average balances

Partially offsetting the earnings decrease was higher earnings of $5.7 million (after tax) due to higher transportation revenue, primarily resulting from higher rates due to a rate case settlement effective in May 2014, and increased volumes.

2014 compared to 2013 Pipeline and midstream earnings increased $17.0 million (220 percent) largely due to:

- Absence of the 2013 impairment of coalbed natural gas gathering assets of $9.0 million (after tax), as discussed in Item 8 - Note 1
- Higher earnings of $5.6 million (after tax) due to increased transportation rates, primarily due to a rate case settlement, and higher volumes
- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, primarily due to higher volumes
- Favorable income tax changes, including $1.0 million of higher income tax benefits

- Lower operation and maintenance expense (excluding the asset impairment, net benefit related to natural gas gathering operations litigation and Pronghorn-related expense), which includes $800,000 (after tax) largely related to legal and abandonment costs offset in part by higher payroll and benefit-related costs

Partially offsetting the earnings increase were:

- Lower storage services earnings of $3.5 million (after tax), largely due to lower average storage balances and lower rates
- Absence of the net benefit in 2013 of $1.5 million (after tax) related to the natural gas gathering operations litigation, as discussed in Item 8 - Note 17

Part II

Construction Materials and Contracting

Years ended December 31,	2015	2014	2013
	(Dollars in millions)		
Operating revenues	$1,904.3	$1,765.3	$1,712.1
Operating expenses:			
Operation and maintenance*	1,652.3	1,571.5	1,505.2
Depreciation, depletion and amortization	65.9	68.6	74.5
Taxes, other than income	40.1	38.8	38.8
	1,758.3	1,678.9	1,618.5
Operating income	146.0	86.4	93.6
Earnings*	$89.1	$51.5	$50.9
Sales (000's):			
Aggregates (tons)	26,959	25,827	24,713
Asphalt (tons)	6,705	6,070	6,228
Ready-mixed concrete (cubic yards)	3,592	3,460	3,223

* Reflects a MEPP withdrawal liability of approximately $2.4 million ($1.5 million after tax) in first quarter 2015 and $14.0 million ($8.4 million after tax) in fourth quarter 2014. For more information, see Item 8 - Note 14.

2015 compared to 2014 Earnings at the construction materials and contracting business increased $37.6 million (73 percent) due to:

- Higher earnings of $9.1 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Higher earnings of $7.2 million (after tax) resulting from higher asphalt margins and volumes, which includes lower asphalt oil costs
- A MEPP withdrawal liability of $1.5 million (after tax) in 2015, compared to $8.4 million (after tax) in 2014, as discussed in Item 8 - Note 14
- Higher earnings of $6.1 million (after tax) resulting from higher construction revenues and margins including the effects of favorable weather
- Higher earnings of $1.6 million (after tax) resulting from higher aggregate margins and volumes
- Higher earnings resulting from higher other product line margins and volumes

Partially offsetting these increases were higher selling, general and administrative expense of $5.7 million (after tax), largely related to higher payroll-related and other costs.

Lower diesel fuel costs contributed to higher earnings from all product lines.

2014 compared to 2013 Earnings at the construction materials and contracting business increased $600,000 (1 percent) due to:

- Favorable income tax changes, which includes $3.1 million related to the resolution of certain income tax matters and higher income tax benefits
- Higher earnings resulting from higher asphalt margins
- Higher earnings of $1.9 million (after tax) resulting from higher ready-mixed concrete volumes and margins
- Higher earnings of $1.7 million (after tax) resulting from higher aggregate margins and volumes
- Lower interest expense of $600,000 (after tax) due to lower average debt balances

Partially offsetting these increases were:

- A MEPP withdrawal liability of $8.4 million (after tax), as discussed in Item 8 - Note 14
- Higher selling, general and administrative expense of $1.9 million (after tax), primarily due to higher payroll and benefit-related costs

Construction Services

Years ended December 31,	2015	2014	2013
	(In millions)		
Operating revenues	$926.4	$1,119.5	$1,039.8
Operating expenses:			
Operation and maintenance	838.5	990.7	910.7
Depreciation, depletion and amortization	13.4	12.9	11.9
Taxes, other than income	31.1	33.6	32.0
	883.0	1,037.2	954.6
Operating income	43.4	82.3	85.2
Earnings	$23.8	$54.5	$52.2

2015 compared to 2014 Construction services earnings decreased $30.7 million (56 percent) due to:

- Lower earnings of $25.1 million (after tax) largely due to lower workloads and margins in the Western region resulting from substantial completion of significant projects in 2014, lower equipment sales and rental margins, lower margins in the Central region and lower electrical supply sales and margins
- The absence of the favorable resolution of certain income tax matters and higher income tax benefits in 2014

These decreases were partially offset by lower selling, general and administrative expense of $3.0 million (after tax), largely related to lower payroll and benefit-related costs.

2014 compared to 2013 Construction services earnings increased $2.3 million (4 percent) due to:

- Favorable income tax changes, which includes $3.9 million related to the resolution of certain income tax matters and higher income tax benefits
- Higher margins, including higher electrical supply sales and margins, higher margins in the Central region and higher workloads and margins in the Western region, partially offset by lower equipment sales revenues

These increases were partially offset by higher selling, general and administrative expense of $3.2 million (after tax), including higher payroll and benefit-related costs.

Refining

Years ended December 31,	2015	2014	2013
	(Dollars in millions)		
Operating revenues	$178.3	$—	$—
Operating expenses:			
Cost of crude oil	159.8	—	—
Operation and maintenance	69.2	7.6	.8
Depreciation, depletion and amortization	16.5	.9	—
Taxes, other than income	1.7	.6	—
	247.2	9.1	.8
Operating loss	(68.9)	(9.1)	(.8)
Loss attributable to the Company	$(22.5)	$(2.1)	$(.1)
Refined product sales (MBbls)			
Diesel fuel	1,072	—	—
Naphtha	996	—	—
ATBs and other	884	—	—
Total refined product sales	2,952	—	—

The earnings variances discussed are the Company's proportionate share while the table includes the noncontrolling interest's portion of operating revenues, operating expenses, operating loss and refined product sales.

Part II

2015 compared to 2014 Refining recognized a loss of $22.5 million compared to a loss of $2.1 million in the prior year due to:

- Higher operation and maintenance expense, which includes $19.1 million (after tax) largely related to higher rail-related costs and higher contract services due to the commencement of operations
- Higher depreciation, depletion and amortization expense, which includes $4.8 million (after tax) due to Dakota Prairie Refinery being placed in service in 2015
- Higher interest expense, which includes $1.2 million (after tax) largely the result of lower capitalized interest and higher average debt

These decreases were partially offset by refined product sales gross margins which have been negatively impacted by market conditions.

2014 compared to 2013 Refining recognized a loss of $2.1 million compared to a loss of $100,000 in the prior year due to:

- Higher operation and maintenance expense, which includes $2.4 million (after tax) largely related to higher payroll and benefit-related costs
- Higher depreciation, depletion and amortization expense, which includes $300,000 (after tax) due to closeouts of certain in-service components

These decreases were partially offset by favorable income tax benefits.

Other

Years ended December 31,	2015	2014	2013
		(In millions)	
Operating revenues	$9.2	$9.4	$9.6
Operating expenses:			
Operation and maintenance	12.7	11.0	11.6
Depreciation, depletion and amortization	2.1	2.2	2.1
Taxes, other than income	.1	.2	.1
	14.9	13.4	13.8
Operating loss	(5.7)	(4.0)	(4.2)
Loss	$(12.4)	$(7.2)	$(10.6)

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

2015 compared to 2014 Other loss increased $5.2 million compared to the prior year primarily due to the absence of prior year income tax benefits; higher operation and maintenance expense, largely a corporate asset impairment; as well as a foreign currency translation loss including the effects of the sale of the Company's remaining interest in the Brazilian Transmission Lines.

2014 compared to 2013 Other loss decreased $3.4 million compared to the prior year primarily due to favorable income tax changes, including the resolution of certain tax matters and higher income tax benefits.

Discontinued Operations

Years ended December 31,	2015	2014	2013
	(In millions)		
Income (loss) from discontinued operations before intercompany eliminations, net of tax	$(774.7)	$114.6	$109.9
Intercompany eliminations	2.3	.5	—
Income (loss) from discontinued operations, net of tax	$(772.4)	$115.1	$109.9

2015 compared to 2014 Discontinued operations recognized a loss of $772.4 million compared to income of $115.1 million in the prior year due to:

- Fair value impairments of the Company's assets held for sale of $475.4 million (after tax), as discussed in Item 8 - Note 2

- A noncash write-down of oil and gas properties of $315.3 million (after tax), as discussed in Item 8 - Note 2
- Lower average realized oil prices of 51 percent, excluding gain/loss on commodity derivatives

Part II

- Decreased oil production of 33 percent, primarily related to the divestment of certain properties in the last half of 2014, deferral of oil drilling activity due to the current low-price environment and the divestment of certain properties in 2015
- Lower average realized natural gas prices of 56 percent, excluding gain/loss on commodity derivatives
- Lower average realized NGL prices of 55 percent, excluding gain/loss on commodity derivatives

Partially offsetting these decreases were:

- Lower depreciation, depletion and amortization expense of $89.6 million (after tax), due to lower depletion rates and volumes and depreciation, depletion and amortization no longer being recorded on assets held for sale
- Lower lease operating expense of $24.0 million (after tax), largely the result of lower cost structures, as well as decreased production

2014 compared to 2013 Discontinued operations experienced an increase in income of $5.2 million compared to the prior year due to:

- Higher average realized natural gas prices of 39 percent, excluding gain/loss on commodity derivatives
- Unrealized gain on commodity derivatives of $14.7 million (after tax) in 2014 compared to an unrealized loss on commodity derivatives of $3.9 million (after tax) in 2013
- Increased oil production of 2 percent, primarily related to the Powder River Basin acquisition and drilling activity in the Paradox Basin
- Higher realized gain on commodity derivatives of $5.2 million (after tax), due to lower commodity prices relative to hedge prices
- Favorable income tax changes related to the resolution of certain income tax matters and higher income tax benefits
- Lower gathering and transportation expense of $1.8 million (after tax), largely due to lower gathering costs resulting from lower volumes

Partially offsetting these increases were:

- Lower average realized oil prices of 7 percent, excluding gain/loss on commodity derivatives
- Decreased natural gas production of 26 percent, largely due to the sale of non-strategic assets
- Higher depreciation, depletion and amortization expense of $6.9 million (after tax), due to higher depletion rates, offset in part by lower volumes
- Decreased NGL production of 22 percent, largely due to the sale of non-strategic assets
- Higher lease operating expenses of $3.8 million (after tax), primarily in the Paradox Basin

The following table represents key statistics of Fidelity's operations:

Years ended December 31,	2015	2014	2013
Production:			
Oil (MBbls)	3,286	4,919	4,815
NGL (MBbls)	393	609	781
Natural gas (MMcf)	16,747	20,822	28,008
Total production (MBOE)	6,471	8,998	10,264
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):			
Oil (per Bbl)	$41.17	$83.33	$89.70
NGL (per Bbl)	$16.14	$36.06	$37.39
Natural gas (per Mcf)	$1.76	$4.02	$2.89
Average realized prices (including realized gain/loss on commodity derivatives):			
Oil (per Bbl)	$48.58	$85.96	$89.35
NGL (per Bbl)	$16.14	$36.06	$37.39
Natural gas (per Mcf)	$2.22	$3.81	$2.96
Production costs, including taxes, per BOE:			

Lease operating costs	$7.76	$9.80	$8.01
Gathering and transportation	1.59	1.38	1.50
Production and property taxes	2.41	5.12	4.54
	$11.76	$16.30	$14.05

Part II

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:

Years ended December 31,	2015	2014	2013
		(In millions)	
Intersegment transactions:			
Operating revenues	$80.9	$136.6	$95.1
Purchased natural gas sold	50.1	44.8	39.3
Operation and maintenance	27.8	81.9	48.7
Depreciation, depletion and amortization	.5	—	—
Income from continuing operations	1.5	6.2	4.3

For more information on intersegment eliminations, see Item 8 - Note 13.

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

Electric and natural gas distribution

- Organic growth opportunities are expected to result in substantial growth of the rate base, which at December 31, 2015, 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.
- 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. Although customer growth was less than peak levels, the Company still saw strong growth in 2015. Due to sustained lower commodity prices, investments of approximately $35 million are expected in 2016.
- The Company, along with a partner, expects to build a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, about 160 miles. The Company’s share of the cost is estimated at approximately $205 million, including development costs and substation upgrade costs. The project has been approved as a MISO multi-value project. More than 90 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 timeframe. 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 also is focused on growth through potential mergers and acquisitions.
- 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. Compliance costs will become clearer as final state plans are completed and submitted to the EPA by September 6, 2018. On February 9, 2016, 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 Company has not included estimates for 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 $28.5 million in final rates and $20.8 million in interim rates. This includes electric rate proceedings in North Dakota, South Dakota and before the FERC, and natural gas proceedings in Minnesota, Montana, North Dakota, Oregon, South Dakota and Wyoming.

Part II

Pending Cases:

- The Company is requesting a total of $59.7 million, including implemented interim rates, in rate relief from pending cases.
- On June 25, 2015, the Company filed an application with the MTPSC for an electric rate increase, as discussed in Item 8 - Note 16. The MTPSC has nine months in which to render a decision on the application.
- On June 30, 2015, the Company filed applications with the SDPUC for electric and natural gas rate increases, as discussed in Item 8 - Note 16. The SDPUC has six months in which to render a decision on the application for an electric rate increase.
- On September 30, 2015 and December 1, 2015, the Company filed applications with the MNPUC and WUTC, respectively, for natural gas rate increases, as discussed in Item 8 - Note 16.
- 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 Item 8 - Note 16.
- On November 25, 2015, the Company 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, as discussed in Item 8 - Note 16.

Expected Filings:

- The Company expects to file electric rate cases in North Dakota and Wyoming in 2016 as well as natural gas rate cases in Idaho and Oregon.

Pipeline and midstream

- The Company has signed agreements to complete two expansion projects, the North Badlands expansion and the Northwest North Dakota expansion. The North Badlands project includes a 4-mile loop of the Garden Creek II pipeline and measurement and associated facilities, expected to be in service in fall of 2016. The Northwest North Dakota project includes modification of existing compression, a new unit and re-cylindering, expected to be in service the summer 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 has been delayed by the plant owner.
- The Company is evaluating expansion into basins beyond its northern Rockies base.
- The Company is focused on 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 December 31, 2015, was $491 million, compared to $438 million a year ago. Private work represents 8 percent of construction backlog and public work represents 92 percent of backlog. The Company recently announced the signing of its largest contract in its history, a $63.4 million highway construction project in Iowa, which is not included in the December 31, 2015, backlog amount.
- 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 Company's market.
- The Company continues to pursue opportunities for expansion in energy projects, such as petrochemical, transmission, wind towers and geothermal. Initiatives are aimed at capturing additional market share and expanding into new markets.
- As the country's fifth-largest sand and gravel producer, the Company will continue to strategically manage its 1.0 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

Construction services

- Approximate work backlog at December 31, 2015, was $493 million, compared to $305 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 $950 million to $1.1 billion in 2016.
- The Company anticipates margins in 2016 to be slightly higher compared to 2015 margins.
- The Company continues to pursue opportunities for expansion in energy projects, such as petrochemical, transmission, substations, utility services and solar. Initiatives are aimed at capturing additional market share and expanding into new markets.

Part II

- 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.

Refining

- Dakota Prairie Refinery processes Bakken crude oil into diesel, which is marketed within the Bakken region. Other by-products, naphtha and ATBs, are transported to other areas. The production slate includes approximately 7,000 - 8,000 BPD of diesel, 5,500 - 6,500 BPD of naphtha and 4,500 - 5,500 BPD of ATBs. Work continues to increase the daily oil processing capacity of the plant.
- Company crude oil purchases for the intake have been at a discount to West Texas Intermediate. However, this discount, or differential, has been much narrower than anticipated because of market conditions in the Bakken.
- Diesel is sold locally at the refinery rack and Dakota Prairie Refinery posts a daily price based on market conditions. Dakota Prairie Refinery's posted diesel prices were in the $40 to $75 per barrel range, with an average $58.65 per barrel, during fourth quarter 2015.
- Naphtha is being railed into Canada to be used as a diluent for tar sands production and is tied to C5 pricing differentials to West Texas Intermediate. Naphtha prices ranged from $35 to $45 per barrel in the fourth quarter of 2015.

New Accounting Standards

For information regarding new accounting standards, see Item 8 - Note 1, which is incorporated herein by reference.

Critical Accounting Policies Involving Significant Estimates

The Company has prepared its financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities, at the date of the financial statements as well as the reported amounts of revenues and expenses during the reporting period. The Company's significant accounting policies are discussed in Item 8 - Note 1.

Estimates are used for items such as impairment testing of assets held for sale, long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; and the valuation of stock-based compensation. The Company's critical accounting policies are subject to judgments and uncertainties that affect the application of such policies. As discussed below, the Company's financial position or results of operations may be materially different when reported under different conditions or when using different assumptions in the application of such policies.

As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates. The following critical accounting policies involve significant judgments and estimates.

Oil and natural gas properties

Estimates of proved reserves are prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The extent, quality and reliability of this data can vary. Other factors used in the reserve estimates are prices, market differentials, estimates of well operating and future development costs, and timing of operations. These estimates are refined as new information becomes available.

As these estimates change, calculated proved reserves may change. Prior to the oil and natural gas properties being classified as held for sale, changes in proved reserve quantities impacted the Company's depreciation, depletion and amortization expense since the Company used the units-of-production method to amortize its oil and natural gas properties. Historically, the proved reserves were used as the basis for the disclosures in Item 8 - Supplementary Financial Information and were the underlying basis of the "ceiling test" for the Company's oil and natural gas properties while those properties were classified as held for use.

Historically, the Company used the full-cost method of accounting for its exploration and production activities. Prior to the oil and natural gas properties being classified as held for sale, capitalized costs were subject to a "ceiling test" that limited 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 were determined based on SEC Defined Prices and excluded cash flows associated with asset retirement obligations that had been accrued on the balance sheet. Judgments and assumptions were made when estimating and valuing proved reserves.

In the second quarter of 2015, the Company announced its plan to market Fidelity and exit that line of business. The assets and liabilities were classified as held for sale and evaluated for impairment based on estimated fair value less cost to sell, as discussed later under Impairment testing of assets held for sale.

Impairment testing of assets held for sale

The Company evaluates disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2015, the estimated fair value was determined using the income and the market approaches. The income approach was determined by using the present value of future estimated cash flows. The income approach considered management’s views on current operating measures as well as assumptions pertaining to market forces in the oil and gas industry including estimated reserves, estimated prices, market differentials, estimates of well operating and future development costs and timing of operations. The estimated cash flows were discounted using a rate believed to be consistent with those used by principal market participants. The market approach was provided by a third party and based on market transactions involving similar interests in oil and natural gas properties. In the third quarter of 2015, the estimated fair value of Fidelity was determined by agreed upon pricing in the purchase and sale agreements for the assets subject to the agreements, the majority of which closed during the fourth quarter of 2015, including customary purchase price adjustments. The values received in the bid proposals were lower than originally anticipated due to lower commodity prices than those projected in the second quarter of 2015. For those assets for which a purchase and sale agreement had not been entered into, which the Company is continuing to market, the fair value was determined based on the market approach utilizing multiples based on similar interests in oil and natural gas properties, as the Company believes this was the most relevant measure of fair value for these assets. In the fourth quarter of 2015, the fair value assessment was determined using the market approach based on purchase and sale agreements, one of which has been signed and one of which the Company is currently negotiating.

Unforeseen events and changes in circumstances and market conditions and material differences in the value of the assets held for sale due to changes in estimates of future cash flows could negatively affect the estimated fair value of Fidelity and result in additional impairment charges. Various factors, including oil and natural gas prices, market differentials and changes in estimates of reserve quantities could result in future impairments of the Company's assets held for sale.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the assets could be different using different estimates and assumptions in the valuation techniques used.

The Company believes its estimates used in calculating the fair value of its assets held for sale are reasonable based on the information that is known when the estimates are made.

Impairment of long-lived assets and intangibles

The Company reviews the carrying values of its long-lived assets and intangibles, excluding assets held for sale and oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and at least annually for goodwill.

Goodwill The Company performs its goodwill impairment testing annually in the fourth quarter. In addition, the test is performed on an interim basis whenever events or circumstances indicate that the carrying amount of goodwill may not be recoverable. Examples of such events or circumstances may include a significant adverse change in business climate, weakness in an industry in which the Company's reporting units operate or recent significant cash or operating losses with expectations that those losses will continue.

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Item 8 - Note 13. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2015, 2014, and 2013, there were no significant impairment losses recorded. At December 31, 2015, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 5 percent to 9 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2015. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Long-Lived Assets Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows could negatively affect the fair value of the Company's assets and result in an impairment charge. If an impairment indicator exists for tangible and intangible assets, excluding goodwill, the asset group held and used is tested for recoverability by comparing an estimate of undiscounted future cash flows attributable to the assets compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value.

There is risk involved when determining the fair value of assets, tangible and intangible, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the asset could be different using different estimates and assumptions in the valuation techniques used.

The Company believes its estimates used in calculating the fair value of long-lived assets, including goodwill and identifiable intangibles, are reasonable based on the information that is known when the estimates are made.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. Critical estimates related to the recognition of revenue include costs on construction contracts under the percentage-of-completion method.

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues and contract costs. Inasmuch as contract prices are generally set before the work is performed, the estimates pertaining to every project could contain significant unknown risks such as volatile labor, material and fuel costs, weather delays, adverse project site conditions, unforeseen actions by regulatory agencies, performance by subcontractors, job management and relations with project owners. Changes in estimates could have a material effect on the Company's results of operations, financial position and cash flows.

Several factors are evaluated in determining the bid price for contract work. These include, but are not limited to, the complexities of the job, past history performing similar types of work, seasonal weather patterns, competition and market conditions, job site conditions, work force safety, reputation of the project owner, availability of labor,

materials and fuel, project location and project completion dates. As a project commences, estimates are continually monitored and revised as information becomes available and actual costs and conditions surrounding the job become known. If a loss is anticipated on a contract, the loss is immediately recognized.
The Company believes its estimates surrounding percentage-of-completion accounting are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job. There were no material changes in contract estimates at the individual contract level in 2015.

Pension and other postretirement benefits

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to these plans. Costs of providing pension and other postretirement benefits bear the risk of change, as they are dependent upon numerous factors based on assumptions of future conditions.

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases, actuarially determined mortality data, and health care cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers historical returns, current market conditions and expected future market trends, including changes in interest rates and equity and bond market performance. Another key variable in determining benefit expense or income is the discount rate. In selecting the discount rate, the Company matches forecasted future cash flows of the pension and postretirement plans to a yield curve which consists of a hypothetical portfolio of high-quality corporate bonds with varying maturity dates, as well as other factors, as a basis. The Company's pension and other postretirement benefit plan assets are primarily made up of equity and fixed-income investments. Fluctuations in actual equity and bond market returns as well as changes in general interest rates may result in increased or decreased pension and other postretirement benefit costs in the future. Management estimates the rate of compensation increase based on long-term assumed wage increases and the health care cost trend rates are determined by historical and future trends. The Company estimates that a 50 basis point decrease in the discount rate or in the expected return on plan assets would each increase expense by less than $1.3 million (after tax) for the year ended December 31, 2015.

The Company believes the estimates made for its pension and other postretirement benefits are reasonable based on the information that is known when the estimates are made. These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will be affected by changes in the discount rate, the expected long-term return on plan assets, the rate of compensation increase and health care cost trend rates. The Company plans to continue to use its current methodologies to determine plan costs. For more information on the assumptions used in determining plan costs, see Item 8 - Note 14.

Income taxes

Income taxes require significant judgments and estimates including the determination of income tax expense, deferred tax assets and liabilities and, if necessary, any valuation allowances that may be required for deferred tax assets and accruals for uncertain tax positions. The effective income tax rate is subject to variability from period to period as a result of changes in federal and state income tax rates and/or changes in tax laws. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states. The Company estimates that a one percent change in the effective tax rate would affect the income tax expense by less than $1.9 million for the year ended December 31, 2015.

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Significant federal tax credit carryforwards and federal and state net operating loss carryforwards have been generated. The Company may not be able to utilize all of these carryforwards prior to their expiration. As a result, the Company has recorded valuation allowances for the amounts it may not be able to utilize. Changes in tax regulations or assumptions regarding current and future taxable income could require a change to the estimated valuation allowances in the future resulting in a material impact to the Company's financial position and results of operations. For more information related to federal and state net operating loss carryforwards, see Item 8 - Notes 2 and 12.

The Company believes its estimates surrounding income taxes are reasonable based on the information that is known when the estimates are made.

Liquidity and Capital Commitments

At December 31, 2015, the Company had cash and cash equivalents of $84.6 million and available capacity of $799.2 million under the outstanding credit facilities of the Company and its subsidiaries. The Company expects to meet its obligations for debt maturing within one year from various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt.

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 exploration and production business.

Cash flows provided by operating activities in 2015 increased $37.5 million from 2014. The increase was primarily due to lower working capital requirements of $205.7 million, primarily at the natural gas distribution business, largely related to lower natural gas sales and the construction services business, largely due to lower workloads; as well as lower income tax payments. Partially offsetting this increase was lower earnings primarily due to lower commodity prices at the exploration and production business.

Cash flows provided by operating activities in 2014 decreased $150.6 million from 2013. The decrease was primarily due to higher working capital requirements of $106.5 million, primarily at the construction services business. Cash flows from discontinued operations were lower largely due to higher working capital requirements at the exploration and production business.

Investing activities Cash flows used in investing activities in 2015 decreased $521.7 million from 2014 primarily due to lower capital expenditures and higher proceeds from the sale of properties, largely at the exploration and production business.

Cash flows used in investing activities in 2014 increased $121.5 million from 2013 primarily due to higher acquisition-related capital expenditures at the exploration and production business, as well as higher capital expenditures, primarily at the refining business. Partially offsetting the increase in cash flows used in investing activities was higher proceeds from the sale of properties at the exploration and production business.

Financing activities Cash flows used in financing activities was $255.7 million in 2015 compared to cash flows provided by financing activities of $325.2 million in 2014. The change was primarily due to the lower issuance of long-term debt of $260.2 million, higher repayment of long-term debt of $201.2 million and lower issuance of common stock.

Cash flows provided by financing activities in 2014 increased $288.3 million from 2013, primarily due to the issuance of $135.5 million of common stock, as well as higher issuance of long-term debt of $98.2 million, a higher cash contribution of $59.9 million related to the noncontrolling interest and lower repayment of long-term debt of $55.5 million. Partially offsetting this increase were higher dividends paid in 2014 compared to 2013 due to the acceleration of the first quarter 2013 quarterly common stock dividend to 2012.

Defined benefit pension plans

The Company has qualified noncontributory defined benefit pension plans for certain employees. Plan assets consist of investments in equity and fixed-income securities. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the pension plans. Actuarial assumptions include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as determined by the Company within certain guidelines. At December 31, 2015, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $110.3 million. Pretax pension expense reflected in the years ended December 31, 2015, 2014 and 2013, was $2.0 million, $1.1 million and $3.0 million, respectively. The Company's pension expense is currently projected to be approximately $2.5 million to $3.5 million in 2016. Funding for the pension plans is actuarially determined. The minimum required contributions for 2015, 2014 and 2013 were approximately $3.9 million, $10.8 million and $13.2 million, respectively. For more information on the Company's pension plans, see Item 8 - Note 14.

Part II

Capital expenditures

The Company's capital expenditures for 2013 through 2015 and as anticipated for 2016 through 2018 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated (a)		
	2013	2014	2015	2016	2017	2018
	(In millions)					
Capital expenditures:						
Electric	$169	$185	$333	$122	$196	$202
Natural gas distribution	101	121	131	145	164	135
Pipeline and midstream	40	62	18	27	73	94
Construction materials and contracting	35	38	48	35	99	76
Construction services	15	27	38	9	12	13
Refining (b)	87	115	22	3	4	3
Other	2	2	4	4	3	2
Net proceeds from sale or disposition of property and other (c)	(29)	(60)	(64)	(3)	(5)	(6)
Net capital expenditures before discontinued operations	420	490	530	342	546	519
Discontinued operations (c)	308	354	(203) (d)	—	—	—
Net capital expenditures	728	844	327	342	546	519
Retirement of long-term debt	424	369	569	244	51	175
	$1,152	$1,213	$896	$586	$597	$694

(a) The Company continues to evaluate potential future acquisitions and other growth opportunities which are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the above estimates.

(b) Reflects the Company's proportionate share of Dakota Prairie Refinery.

(c) Proceeds from the sale of the exploration and production assets are excluded from capital expenditure projections.

(d) Capital expenditures from discontinued operations includes gross proceeds of $316.6 million from the sale of the exploration and production assets, which does not include purchase price adjustments and income tax benefits.

Capital expenditures for 2015, 2014 and 2013 in the preceding table include noncash capital expenditure-related accounts payable and exclude capital expenditures of the noncontrolling interest related to Dakota Prairie Refinery. These net transactions were $(40.5) million in 2015, $(88.8) million in 2014 and $(70.0) million in 2013.

The 2015 capital expenditures, including those for the retirement of long-term debt, were met from internal sources and the issuance of long-term debt and the Company's equity securities. Estimated capital expenditures for the years 2016 through 2018 include those for:

- 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, including certain costs for additional electric generating capacity
- Environmental upgrades
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. It is anticipated that all of the funds required for capital expenditures and retirement of long-term debt for the years 2016 through 2018 will be met from various sources, including internally generated funds; the Company's credit facilities, as described later; through the issuance of long-term debt and the Company's equity securities; and asset sales.

Part II

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 December 31, 2015. 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 Item 8 - Note 7.
The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2015:

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		$44.5	(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)	$47.9		$—		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$650.0		$18.0	(b)	$39.4		5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement		$75.0		$45.5		$18.3	(d)	6/30/16

(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 2.5 times and 3.1 times for the 12 months ended December 31, 2015 and 2014, respectively.

Total equity as a percent of total capitalization was 57 percent and 61 percent at December 31, 2015 and 2014, respectively. This ratio is calculated as the Company's total equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus total equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

On May 20, 2013, the Company entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 7.5 million shares of the Company's common stock. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement. Sales of such common stock may not be made after February 28, 2016, in accordance with the terms and conditions of the agreement. Proceeds from the shares of common stock under the agreement have been 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, 2015 and December 31, 2015. 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 December 31, 2015.

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. WBI Energy Transmission has a $175.0 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2015, which reduced capacity under this uncommitted private shelf agreement.

Dakota Prairie Refining, LLC On September 30, 2015, Dakota Prairie Refining entered into an amendment to its revolving credit agreement which increased the borrowing limit from $50.0 million under the original December 1, 2014, agreement to $75.0 million and extended the termination date from December 1, 2015 to June 30, 2016. The credit agreement is used to meet the operational needs of the facility.

Off balance sheet arrangements

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

Contractual obligations and commercial commitments

For more information on the Company's contractual obligations on long-term debt, operating leases and purchase commitments, see
Item 8 - Notes 7 and 17. At December 31, 2015, the Company's commitments under these obligations were as follows:

	2016	2017	2018	2019	2020	Thereafter	Total
	(In millions)						
Long-term debt	$243.8	$51.0	$175.2	$119.7	$21.0	$1,260.5	$1,871.2
Estimated interest payments*	80.1	70.9	69.3	61.3	58.9	527.8	868.3
Operating leases	52.3	42.7	35.5	26.4	15.9	76.9	249.7
Purchase commitments	443.7	228.0	138.9	112.9	90.4	853.9	1,867.8

	$819.9	$392.6	$418.9	$320.3	$186.2	$2,719.1	$4,857.0

*Estimated interest payments are calculated based on the applicable rates and payment dates.

At December 31, 2015, the Company had total liabilities of $242.2 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was $4.5 million at December 31, 2015, and was included in other accrued liabilities on the Consolidated Balance Sheet. The remainder, which constitutes the long-term portion of asset retirement obligations, was included in other liabilities on the Consolidated Balance Sheet. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. For more information, see Item 8 - Note 8.

Part II

The Company has no uncertain tax positions and no minimum funding requirements for its defined benefit pension plans for 2016.
The Company's MEPP contributions are based on union employee payroll, which cannot be determined in advance for future periods. The Company may also be required to make additional contributions to its MEPPs as a result of their funded status. For more information, see Item 1A - Risk Factors and Item 8 - Note 14.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2015, 2014 or 2013.

Item 7A. 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 derivatives and the Company's derivative policies and procedures, see Item 8 - Consolidated Statements of Comprehensive Income and Notes 1 and 5.

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 December 31, 2015. The following table summarizes derivative agreements entered into by Fidelity as of December 31, 2014. These agreements called for Fidelity to receive fixed prices and pay variable prices.
(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Oil swap agreements maturing in 2015	$98.00	270	$11,895
Natural gas swap agreements maturing in 2015	$4.31	5,000	$6,440

Interest rate risk

The Company uses fixed and variable rate long-term debt to partially finance capital expenditures and mandatory debt retirements. These debt agreements expose the Company to market risk related to changes in interest rates. The Company manages this risk by taking advantage of market conditions when timing the placement of long-term financing. The Company from time to time uses interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk.
At December 31, 2015 and 2014, the Company had no outstanding interest rate hedges.
The following table shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2015.

	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
	(Dollars in millions)							
Long-term debt:								
Fixed rate	$238.5	$43.5	$108.6	$51.2	$15.0	$1,235.0	$1,691.8	$1,715.5
Weighted average interest rate	6.4%	6.3%	6.1%	4.3%	5.2%	4.9%	5.2%	—
Variable rate	$5.3	$7.5	$66.6	$68.5	$6.0	$25.5	$179.4	$177.9
Weighted average interest rate	1.8%	2.1%	1.8%	.9%	2.2%	2.5%	1.6%	—

Part II

Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

The management of MDU Resources Group, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (2013).

Based on our evaluation under the framework in Internal Control-Integrated Framework (2013), management concluded that the Company's internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2015, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

/s/ David L. Goodin	/s/ Doran N. Schwartz
David L. Goodin	Doran N. Schwartz
President and Chief Executive Officer	Vice President and Chief Financial Officer

Part II

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of MDU Resources Group, Inc.

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MDU Resources Group, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 19, 2016

Part II

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of MDU Resources Group, Inc.

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2015 of the Company and our report dated February 19, 2016 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 19, 2016

Part II

Consolidated Statements of Income

Years ended December 31,	2015	2014	2013
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and regulated pipeline and midstream	$1,148,272	$1,246,646	$1,156,838
Nonregulated pipeline and midstream, construction materials and contracting, construction services, refining and other	3,043,277	2,868,170	2,763,333
Total operating revenues	4,191,549	4,114,816	3,920,171
Operating expenses:			
Fuel and purchased power	86,238	89,312	83,528
Purchased natural gas sold	450,114	558,463	495,471
Cost of crude oil	159,811	—	—
Operation and maintenance:			
Electric, natural gas distribution and regulated pipeline and midstream	277,638	269,225	253,214
Nonregulated pipeline and midstream, construction materials and contracting, construction services, refining and other	2,593,300	2,529,020	2,426,145
Depreciation, depletion and amortization	227,730	203,980	200,398
Taxes, other than income	142,585	145,393	140,713
Total operating expenses	3,937,416	3,795,393	3,599,469
Operating income	254,133	319,423	320,702
Other income	19,232	9,873	6,086
Interest expense	93,068	86,906	83,803
Income before income taxes	180,297	242,390	242,985
Income taxes	65,603	63,227	74,294
Income from continuing operations	114,694	179,163	168,691
Income (loss) from discontinued operations, net of tax (Note 2)	(772,385)	115,175	109,879
Net income (loss)	(657,691)	294,338	278,570
Net loss attributable to noncontrolling interest	(35,256)	(3,895)	(363)
Dividends declared on preferred stocks	685	685	685
Earnings (loss) on common stock	$(623,120)	$297,548	$278,248
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	$.77	$.95	$.89
Discontinued operations, net of tax	(3.97)	.60	.58
Earnings (loss) per common share - basic	$(3.20)	$1.55	$1.47
Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	$.77	$.95	$.89
Discontinued operations, net of tax	(3.97)	.60	.58
Earnings (loss) per common share - diluted	$(3.20)	$1.55	$1.47
Weighted average common shares outstanding - basic	194,928	192,507	188,855
Weighted average common shares outstanding - diluted	194,986	192,587	189,693

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

Part II

Consolidated Statements of Comprehensive Income

Years ended December 31,	2015	2014	2013
	(In thousands)		
Net income (loss)	$(657,691)	$294,338	$278,570
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized loss on derivative instruments arising during the period, net of tax of $0, $0 and $(3,116) in 2015, 2014 and 2013, respectively	—	—	(5,594)
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of $233, $240 and $339 in 2015, 2014 and 2013, respectively	404	399	727
Reclassification adjustment for (gain) loss on derivative instruments included in income (loss) from discontinued operations, net of tax of $0, $173 and $(2,887) in 2015, 2014 and 2013, respectively	—	295	(4,916)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	404	694	(9,783)
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $(55), $(7,665) and $11,818 in 2015, 2014 and 2013, respectively	(88)	(12,409)	18,539
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of $1,128, $492 and $1,276 in 2015, 2014 and 2013, respectively	1,794	796	2,001
Reclassification of postretirement liability adjustment to regulatory asset, net of tax of $1,416, $4,509 and $0 in 2015, 2014 and 2013, respectively	2,255	7,202	—
Postretirement liability adjustment	3,961	(4,411)	20,540
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $(105), $(99) and $(177) in 2015, 2014 and 2013, respectively	(173)	(162)	(299)
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss), net of tax of $490, $0 and $70 in 2015, 2014 and 2013, respectively	802	—	143
Foreign currency translation adjustment	629	(162)	(156)
Net unrealized loss on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(91), $(83) and $(105) in 2015, 2014 and 2013, respectively	(170)	(154)	(194)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of $70, $73 and $59 in 2015, 2014 and 2013, respectively	131	135	109
Net unrealized loss on available-for-sale investments	(39)	(19)	(85)
Other comprehensive income (loss)	4,955	(3,898)	10,516
Comprehensive income (loss)	(652,736)	290,440	289,086
Comprehensive loss attributable to noncontrolling interest	(35,256)	(3,895)	(363)

Comprehensive income (loss) attributable to common stockholders	$(617,480)	$294,335	$289,449

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

Part II

Consolidated Balance Sheets

December 31,	2015	2014
(In thousands, except shares and per share amounts)		
Assets		
Current assets:		
Cash and cash equivalents	$84,591	$81,855
Receivables, net	590,105	599,186
Inventories	253,727	289,410
Deferred income taxes	32,849	32,012
Prepayments and other current assets	35,189	83,763
Current assets held for sale	24,581	131,177
Total current assets	1,021,042	1,217,403
Investments	119,704	117,883
Property, plant and equipment (Note 1)	6,817,668	6,294,778
Less accumulated depreciation, depletion and amortization	2,506,571	2,386,113
Net property, plant and equipment	4,311,097	3,908,665
Deferred charges and other assets:		
Goodwill (Note 3)	635,204	635,204
Other intangible assets, net (Note 3)	7,342	9,840
Other	366,485	322,943
Noncurrent assets held for sale	166,734	1,620,470
Total deferred charges and other assets	1,175,765	2,588,457
Total assets	$6,627,608	$7,832,408
Liabilities and Equity		
Current liabilities:		
Short-term borrowings (Note 7)	$45,500	$—
Long-term debt due within one year	243,789	268,552
Accounts payable	310,466	279,115
Taxes payable	45,775	39,955
Dividends payable	36,784	35,607
Accrued compensation	46,130	57,402
Other accrued liabilities	171,592	155,765
Current liabilities held for sale	47,603	154,728
Total current liabilities	947,639	991,124
Long-term debt (Note 7)	1,627,443	1,825,278
Deferred credits and other liabilities:		
Deferred income taxes	720,319	714,022
Other liabilities	811,659	756,759
Noncurrent liabilities held for sale	—	295,441
Total deferred credits and other liabilities	1,531,978	1,766,222
Commitments and contingencies (Notes 14, 16 and 17)		
Equity:		
Preferred stocks (Note 9)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 10)		
Authorized - 500,000,000 shares, $1.00 par value	195,805	194,755
Issued - 195,804,665 shares in 2015 and 194,754,812 shares in 2014		

Other paid-in capital	1,230,119	1,207,188
Retained earnings	996,355	1,762,827
Accumulated other comprehensive loss	(37,148)	(42,103)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,381,505	3,119,041
Total stockholders' equity	2,396,505	3,134,041
Noncontrolling interest	124,043	115,743
Total equity	2,520,548	3,249,784
Total liabilities and equity	$6,627,608	$7,832,408

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

Part II

Consolidated Statements of Equity
Years ended December 31, 2015, 2014 and 2013

	Preferred Stock		Common Stock		Other Paid-in Capital	Retained Earnings	Accumu-lated Other Compre-hensive Loss	Treasury Stock		Noncon-trollin Interest	Tota
	Shares	Amount	Shares	Amount				Shares	Amount		
	(In thousands, except shares)										
Balance at December 31, 2012	150,000	$15,000	189,369,450	$189,369	$1,039,080	$1,457,146	$(48,721)	(538,921)	$(3,626)	$—	$2,6
Net income (loss)	—	—	—	—	—	278,933	—	—	—	(363)	278
Other comprehensive income	—	—	—	—	—	—	10,516	—	—	—	10,5
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685
Dividends declared on common stock	—	—	—	—	—	(132,264)	—	—	—	—	(132
Stock-based compensation	—	—	—	—	5,281	—	—	—	—	—	5,28
Net tax deficit on stock-based compensation	—	—	—	—	(1,419)	—	—	—	—	—	(1,4
Issuance of common stock	—	—	499,330	500	14,054	—	—	—	—	—	14,5
Contribution from non-controlling interest	—	—	—	—	—	—	—	—	—	33,101	33,1
Balance at December 31, 2013	150,000	15,000	189,868,780	189,869	1,056,996	1,603,130	(38,205)	(538,921)	(3,626)	32,738	2,85
Net income (loss)	—	—	—	—	—	298,233	—	—	—	(3,895)	294
Other comprehensive loss	—	—	—	—	—	—	(3,898)	—	—	—	(3,8
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685
Dividends declared on common stock	—	—	—	—	—	(137,851)	—	—	—	—	(137
	—	—	—	—	6,191	—	—	—	—	—	6,19

Stock-based compensation											
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	326,122	326	(5,890)	—	—	—	—	—	(5,5
Excess tax benefit on stock-based compensation	—	—	—	—	4,729	—	—	—	—	—	4,72
Issuance of common stock	—	—	4,559,910	4,560	145,162	—	—	—	—	—	149,
Contribution from non-controlling interest	—	—	—	—	—	—	—	—	—	86,900	86,9
Balance at December 31, 2014	150,000	15,000	194,754,812	194,755	1,207,188	1,762,827	(42,103)	(538,921)	(3,626)	115,743	3,24
Net loss	—	—	—	—	—	(622,435)	—	—	—	(35,256)	(657
Other comprehensive income	—	—	—	—	—	—	4,955	—	—	—	4,95
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685
Dividends declared on common stock	—	—	—	—	—	(143,352)	—	—	—	—	(143
Stock-based compensation	—	—	—	—	3,689	—	—	—	—	—	3,68
Net tax deficit on stock-based compensation	—	—	—	—	(1,606)	—	—	—	—	—	(1,6
Issuance of common stock	—	—	1,049,853	1,050	20,848	—	—	—	—	—	21,8
Contribution from non-controlling interest	—	—	—	—	—	—	—	—	—	52,000	52,0
Distribution to non-controlling interest	—	—	—	—	—	—	—	—	—	(8,444)	(8,4
Balance at December 31, 2015	150,000	$15,000	195,804,665	$195,805	$1,230,119	$996,355	$(37,148)	(538,921)	$(3,626)	$124,043	$2,5

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

Part II

Consolidated Statements of Cash Flows

Years ended December 31,	2015	2014	2013
	(In thousands)		
Operating activities:			
Net income (loss)	$(657,691)	$294,338	$278,570
Income (loss) from discontinued operations, net of tax	(772,385)	115,175	109,879
Income from continuing operations	114,694	179,163	168,691
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	227,730	203,980	200,398
Deferred income taxes	301	58,990	28,551
Excess tax benefit on stock-based compensation	—	(4,729)	—
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(313)	4,010	(25,635)
Inventories	(17,100)	(22,795)	28,292
Other current assets	50,097	(40,617)	(13,569)
Accounts payable	49,117	(42,138)	26,285
Other current liabilities	6,325	(15,988)	(26,360)
Other noncurrent changes	10,256	(21,450)	(30,786)
Net cash provided by continuing operations	441,107	298,426	355,867
Net cash provided by discontinued operations	200,037	305,241	398,441
Net cash provided by operating activities	641,144	603,667	754,308
Investing activities:			
Capital expenditures	(625,375)	(608,028)	(531,332)
Acquisitions, net of cash acquired	—	(269)	—
Net proceeds from sale or disposition of property and other	54,569	29,598	40,802
Investments	1,515	(1,041)	302
Proceeds from sale of equity method investments	—	—	1,896
Net cash used in continuing operations	(569,291)	(579,740)	(488,332)
Net cash provided by (used in) discontinued operations	186,838	(324,451)	(294,329)
Net cash used in investing activities	(382,453)	(904,191)	(782,661)
Financing activities:			
Issuance of short-term borrowings	45,500	—	9,500
Repayment of short-term borrowings	—	(11,500)	—
Issuance of long-term debt	345,920	606,084	507,924
Repayment of long-term debt	(569,498)	(368,249)	(423,707)
Proceeds from issuance of common stock	21,898	150,060	14,554
Dividends paid	(142,835)	(136,712)	(98,405)
Excess tax benefit on stock-based compensation	—	4,729	—
Tax withholding on stock-based compensation	—	(5,564)	—
Contribution from noncontrolling interest	52,000	86,900	27,000
Distribution to noncontrolling interest	(8,444)	—	—
Net cash provided by (used in) continuing operations	(255,459)	325,748	36,866
Net cash used in discontinued operations	(271)	(554)	—
Net cash provided by (used in) financing activities	(255,730)	325,194	36,866
Effect of exchange rate changes on cash and cash equivalents	(225)	(155)	(215)
Increase in cash and cash equivalents	2,736	24,515	8,298

Cash and cash equivalents - beginning of year	81,855	57,340	49,042
Cash and cash equivalents - end of year	$84,591	$81,855	$57,340

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

Notes to Consolidated Financial Statements
Note 1 - Summary of Significant Accounting Policies
Basis of presentation
The abbreviations and acronyms used throughout are defined following the Notes to Consolidated Financial Statements. The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, construction services, refining and other. The electric and natural gas distribution businesses, as well as a portion of the pipeline and midstream business, are regulated. Construction materials and contracting, construction services, refining and the other businesses, as well as a portion of the pipeline and midstream business, are nonregulated. For further descriptions of the Company's businesses, see Note 13. Intercompany balances and transactions have been eliminated in consolidation, except for certain transactions related to the Company's regulated operations in accordance with GAAP. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.
The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.
The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 4 for more information regarding the nature and amounts of these regulatory deferrals.
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 December 31, 2015, up to the date of issuance of these consolidated financial statements.
In the second quarter of 2015, the Company announced its plan to market Fidelity, previously referred to as the Company's exploration and production segment, and exit that line of business. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated to present the results of operations of Fidelity as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former exploration and production segment and do not meet the criteria for income (loss) from discontinued operations. In addition, the assets and liabilities have been treated and classified as held for sale. 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 discontinued operations, see Note 2.
Cash and cash equivalents
The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.
Accounts receivable and allowance for doubtful accounts
Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. For more information, see Percentage-of-completion method in this note. The total balance of receivables past due 90 days or more was $27.8 million and $29.4 million at December 31, 2015 and 2014, 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 December 31, 2015 and 2014, was $9.8 million and $9.5 million, respectively.

Part II

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. Crude oil and refined products at Dakota Prairie Refinery are carried at lower of cost or market value using the last-in, first-out method. In 2015, Dakota Prairie Refinery recorded $12.2 million (before tax) of inventory impairments due to the lower of cost or market valuation which is reflected in cost of crude oil on the Consolidated Statements of Income. 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 was included in inventories.

Inventories at December 31 consisted of:

	2015	2014
	(In thousands)	
Aggregates held for resale	$115,854	$108,161
Asphalt oil	36,498	42,135
Materials and supplies	16,997	54,282
Merchandise for resale	15,318	24,420
Refined products	8,498	—
Natural gas in storage (current)	21,023	19,302
Crude oil	4,678	5,045
Other	34,861	36,065
Total	$253,727	$289,410

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $49.1 million and $49.3 million at December 31, 2015 and 2014, respectively.

Investments

The Company's investments include the cash surrender value of life insurance policies, an insurance contract, mortgage-backed securities and U.S. Treasury securities. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair value option for its mortgage-backed securities and U.S. Treasury securities and, as a result, the unrealized gains and losses on these investments are recorded in accumulated other comprehensive income (loss). For more information, see Notes 6 and 14.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized for the years ended December 31 were as follows:

	2015	2014	2013
		(In thousands)	
Interest capitalized	$4,902	$8,586	$6,033
AFUDC - borrowed	$4,907	$3,022	$2,767
AFUDC - equity	$7,971	$5,803	$3,322

Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

Part II

Property, plant and equipment at December 31 was as follows:

	2015	2014	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$1,003,173	$627,952	39
Distribution	375,612	343,692	44
Transmission	255,842	229,997	57
Construction in progress	42,436	150,445	-
Other	109,085	105,015	14
Natural gas distribution:			
Distribution	1,624,645	1,481,390	35
Construction in progress	20,530	59,310	-
Other	431,406	364,059	22
Pipeline and midstream:			
Transmission	460,305	449,276	53
Gathering	37,831	39,595	20
Storage	44,011	43,994	60
Construction in progress	7,549	5,386	-
Other	40,168	39,910	33
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	158,949	227,598	16
Construction in progress	89	691	-
Other	9,827	11,938	10
Construction materials and contracting:			
Land	123,723	125,372	-
Buildings and improvements	69,011	70,566	19
Machinery, vehicles and equipment	937,084	921,564	12
Construction in progress	18,615	8,709	-
Aggregate reserves	404,995	403,731	*
Construction services:			
Land	6,460	5,265	-
Buildings and improvements	23,824	17,936	25
Machinery, vehicles and equipment	121,940	112,973	6
Other	11,055	8,221	3
Refining:			
Refinery	445,198	88,232	20
Construction in progress	135	313,613	-
Other:			
Land	2,837	2,837	-
Other	46,700	48,100	23
Eliminations	(15,367)	(12,589)	
Less accumulated depreciation, depletion and amortization	2,506,571	2,386,113	

Net property, plant and equipment	$4,311,097	$3,908,665

*Depleted on the units-of-production method.

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill, oil and natural gas properties, and assets held for sale, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In the third quarter of 2015, the Company recognized an impairment of $14.1 million (before tax) related to the sale of certain non-strategic natural gas gathering assets that were written down to their estimated fair value that was determined using the market approach. In the second quarters of 2015 and 2013, the Company recognized impairments of $3.0 million (before tax) and $14.5 million (before tax), respectively, related to coalbed natural gas gathering assets located in Wyoming and Montana where there has been a continued decline in natural gas development and production activity largely due to low natural gas prices. The coalbed natural gas gathering assets were written down to their estimated fair value that was determined using the income approach. The impairments are recorded in operation and maintenance expense on the Consolidated Statements of Income. For more information on these nonrecurring fair value measurements, see Note 6.

No significant impairment losses were recorded in 2014. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Note 13. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2015, 2014 and 2013, there were no significant impairment losses recorded. At December 31, 2015, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 5 percent to 9 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2015. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $102.1 million and $99.7 million at December 31, 2015 and 2014, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized.

Costs and estimated earnings in excess of billings on uncompleted contracts represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts represent billings in excess of revenues recognized and were included in accounts payable.

Costs and estimated earnings in excess of billings and billings in excess of costs and estimated earnings on uncompleted contracts at December 31 were as follows:

	2015	2014
	(In thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	$64,369	$58,243
Billings in excess of costs and estimated earnings on uncompleted contracts	$68,048	$47,011

Amounts representing balances billed but not paid by customers under retainage provisions in contracts at December 31 were as follows:

	2015	2014
	(In thousands)	
Short-term retainage*	$46,207	$47,551
Long-term retainage**	1,605	1,053
Total retainage	$47,812	$48,604

*Expected to be paid within one year or less and included in receivables, net.

**Included in deferred charges and other assets - other.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price and interest rate risk management program to efficiently manage and minimize commodity price and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties.

The Company's policy generally allows the hedging of monthly forecasted sales of oil and natural gas production for a period up to 42 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical oil and natural gas production occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value. The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 5.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 8.

Legal costs

The Company expenses external legal fees as they are incurred.

Part II

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments which are filed annually. Natural gas costs refundable through rate adjustments were $20.9 million and $13.2 million at December 31, 2015 and 2014, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $547,000 and $19.6 million at December 31, 2015 and 2014, respectively, which is included in prepayments and other current assets.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

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 year. 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 year, plus the effect of outstanding performance share awards. In 2015, 2014 and 2013, there were no shares excluded from the calculation of diluted earnings per share. 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 calculation was as follows:

	2015	2014	2013
		(In thousands)	
Weighted average common shares outstanding - basic	194,928	192,507	188,855
Effect of dilutive performance share awards	58	80	838
Weighted average common shares outstanding - diluted	194,986	192,587	189,693
Shares excluded from the calculation of diluted earnings per share	—	—	—

Use of estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of assets held for sale, long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; and the valuation of stock-based compensation. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Part II

Cash flow information

Cash expenditures for interest and income taxes for the years ended December 31 were as follows:

	2015	2014	2013
		(In thousands)	
Interest, net of amount capitalized and AFUDC - borrowed of $9,809, $11,608 and $8,800 in 2015, 2014 and 2013, respectively	$90,386	$81,241	$81,575
Income taxes paid, net	$33,409	$64,211	$52,580

Noncash investing transactions at December 31 were as follows:

	2015	2014	2013
		(In thousands)	
Property, plant and equipment additions in accounts payable	$51,702	$62,453	$22,832

New accounting standards

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity In April 2014, the FASB issued guidance related to the definition and reporting of discontinued operations. The guidance changed the definition of discontinued operations to include only disposals of a component or group of components that represent a strategic shift and that have a major effect on an entity's operations or financial results. The guidance also expands the disclosure requirements for transactions that meet the definition of a discontinued operation, and also requires entities to disclose information about individually significant components that are disposed of or held for sale that do not meet the definition of a discontinued operation. This guidance was effective for the Company on January 1, 2015, and is to be applied prospectively. The adoption required additional disclosures for the Company's discontinued operations, however it did not impact the Company's results of operations, financial position or cash flows.

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 has not elected to do so. The guidance will require a reclassification of the debt issuance costs on the Consolidated Balance Sheets, but will not impact the Company's results of operations or cash flows.

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 Company is evaluating the effects the adoption of the new guidance will have on its disclosures, however it will 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.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

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

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

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gains (losses) on available-for-sale investments. For more information on derivative instruments, see Note 5.

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The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2015, 2014 and 2013, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2013	$(3,765)	$(33,807)	$(667)	$34	$(38,205)
Other comprehensive income (loss) before reclassifications	—	(12,409)	(162)	(154)	(12,725)
Amounts reclassified from accumulated other comprehensive loss	694	796	—	135	1,625
Amounts reclassified from accumulated other comprehensive loss to a regulatory asset	—	7,202	—	—	7,202
Net current-period other comprehensive income (loss)	694	(4,411)	(162)	(19)	(3,898)
Balance at December 31, 2014	(3,071)	(38,218)	(829)	15	(42,103)
Other comprehensive income (loss) before reclassifications	—	(88)	(173)	(170)	(431)
Amounts reclassified from accumulated other comprehensive loss	404	1,794	802	131	3,131
Amounts reclassified from accumulated other comprehensive loss to a regulatory asset	—	2,255	—	—	2,255
Net current-period other comprehensive income (loss)	404	3,961	629	(39)	4,955
Balance at December 31, 2015	$(2,667)	$(34,257)	$(200)	$(24)	$(37,148)

Reclassifications out of accumulated other comprehensive loss for the years ended December 31 were as follows:

	2015	2014	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income (loss):			
Interest rate derivative instruments	$(637)	$(639)	Interest expense
	233	240	Income taxes
	(404)	(399)	
Commodity derivative instruments, net of tax	—	(295)	Income (loss) from discontinued operations, net of tax
	(404)	(694)	
	(2,922)	(1,288)	(a)

Amortization of postretirement liability losses included in net periodic benefit cost (credit)			
	1,128	492	Income taxes
	(1,794)	(796)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss)	(1,292)	—	Other income
	490	—	Income taxes
	(802)	—	
Reclassification adjustment for loss on available-for-sale investments included in net income (loss)	(201)	(208)	Other income
	70	73	Income taxes
	(131)	(135)	
Total reclassifications	$(3,131)	$(1,625)	

(a) Included in net periodic benefit cost (credit). For more information, see Note 14.

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Note 2 - Discontinued Operations
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. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. The completion of the majority of these sales occurred in the fourth quarter of 2015 and the Company continues to market the remaining assets of Fidelity. The sale of Fidelity is 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 these operations have been classified as held for sale and the results of operations are shown in income (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.

The carrying amounts of the major classes of assets and liabilities that are classified as held for sale on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2015	2014
	(In thousands)	
Assets		
Current assets:		
Receivables, net	$13,387	$94,132
Inventories	1,308	11,401
Commodity derivative instruments	—	18,335
Prepayments and other current assets	9,886	7,309
Total current assets held for sale	24,581	131,177
Noncurrent assets:		
Investments	37	37
Net property, plant and equipment	793,422	1,618,099
Deferred income taxes	127,655	—
Other	161	2,334
Less allowance for impairment of assets held for sale	754,541	—
Total noncurrent assets held for sale	166,734	1,620,470
Total assets held for sale	$191,315	$1,751,647
Liabilities		
Current liabilities:		
Long-term debt due within one year	$—	$897
Accounts payable	25,013	103,556
Taxes payable	1,052	19,900
Deferred income taxes	3,620	8,206
Accrued compensation	13,080	5,373
Other accrued liabilities	4,838	16,796
Total current liabilities held for sale	47,603	154,728
Noncurrent liabilities:		
Deferred income taxes	—	238,391
Other liabilities	—	57,050
Total noncurrent liabilities held for sale	—	295,441
Total liabilities held for sale	$47,603	$450,169

At December 31, 2015, the Company's deferred tax assets included in assets held for sale were largely comprised of $78.9 million of federal and state net operating loss carryforwards and $38.1 million of basis differences on oil and natural gas producing properties. At December 31, 2014, the Company's deferred tax liabilities included in liabilities held for sale were largely comprised of $270.0 million of basis differences on oil and natural gas producing properties offset in part by $26.4 million of asset retirement obligations.

The Company had federal income tax net operating loss carryforwards of $208.2 million at December 31, 2015, and no federal income tax net operating loss carryforwards at December 31, 2014. At December 31, 2015 and 2014, the Company had various state income tax net operating loss carryforwards of $201.4 million and $5.9 million, respectively. The federal net operating loss carryforwards expire in 2036 if not utilized. The state net operating loss carryforwards are due to expire between 2016 and 2036. It is likely a portion of the benefit from

Part II

the state carryforwards will not be realized; therefore, valuation allowances of $300,000 and $253,000 have been provided in 2015 and 2014, respectively.
The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2015, the estimated fair value was determined using the income and the market approaches. The income approach was determined by using the present value of future estimated cash flows. The income approach considered management’s views on current operating measures as well as assumptions pertaining to market forces in the oil and gas industry including estimated reserves, estimated prices, market differentials, estimates of well operating and future development costs and timing of operations. The estimated cash flows were discounted using a rate believed to be consistent with those used by principal market participants. The market approach was provided by a third party and based on market transactions involving similar interests in oil and natural gas properties. The fair value assessment indicated an impairment based on the carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity’s assets at June 30, 2015, and recording an impairment of $400.0 million ($252.0 million after tax) during the second quarter of 2015. In the third quarter of 2015, the estimated fair value of Fidelity was determined by agreed upon pricing in the purchase and sale agreements for the assets subject to the agreements, the majority of which closed during the fourth quarter of 2015, including customary purchase price adjustments. The values received in the bid proposals were lower than originally anticipated due to lower commodity prices than those projected in the second quarter of 2015. For those assets for which a purchase and sale agreement has not been entered into, which the Company is continuing to market, the fair value was determined based on the market approach utilizing multiples based on similar interests in oil and natural gas properties. The fair value assessment indicated an impairment based on the current carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity’s assets at September 30, 2015, and recording an impairment of $356.1 million ($224.4 million after tax). In the fourth quarter of 2015, the fair value assessment was determined using the market approach based on purchase and sale agreements, one of which has been signed and one of which the Company is currently negotiating. The estimated fair value exceeded the carrying value and the Company recorded an impairment reversal of $1.6 million ($1.0 million after tax) in the fourth quarter of 2015. The impairments 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.
At December 31, 2015, the Company has accrued liabilities of approximately $2.5 million for estimated transaction costs which will result in future cash expenditures. In addition to the estimated 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 $4.9 million of exit and disposal costs in 2015 and expects to incur an additional $6.1 million of exit and disposal costs in 2016. The exit and disposal costs are associated with severance and other related matters, excluding the office lease expenses discussed in the following paragraph. The majority of these exit and disposal activities are expected to be completed by the end of the second quarter of 2016.
Fidelity is vacating its office space in Denver, Colorado. An amendment of lease has been executed with payments of $4.2 million required under the lease in 2016. A termination payment of $3.3 million was made during the fourth quarter of 2015 and existing office furniture and fixtures will be relinquished to the lessor in 2016.
Unforeseen events and changes in circumstances and market conditions and material differences in the value of the assets held for sale due to changes in estimates of future cash flows could negatively affect the estimated fair value of Fidelity and result in additional impairment charges. Various factors, including oil and natural gas prices, market differentials and changes in estimates of reserve quantities could result in future impairments of the Company's assets held for sale.
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.

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On February 10, 2014, the Company entered into agreements to purchase working interests and leasehold positions in oil and natural gas production assets in the southern Powder River Basin of Wyoming. The effective date of the acquisition was October 1, 2013, and the closing occurred on March 6, 2014. The total purchase price, including purchase price adjustments, for acquisitions in 2014 was approximately $209.2 million, including the above acquisition which is reflected in discontinued operations. Pro forma financial amounts reflecting the effects of the acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. The Company incurred legal expenses and had a benefit related to the resolution of this matter in the second quarter of 2014, which are reflected in discontinued operations in the consolidated financial statements and accompanying notes.

The reconciliation of the major classes of income and expense constituting pretax income (loss) from discontinued operations to the after-tax net income (loss) from discontinued operations of the Company's Consolidated Statements of Income at December 31 were as follows:

	2015	2014	2013
	(In thousands)		
Operating revenues	$184,853	$547,571	$536,023
Operating expenses	1,423,037	378,891	364,120
Operating income (loss)	(1,238,184)	168,680	171,903
Other income	2,374	1,163	549
Interest expense	235	110	114
Income (loss) from discontinued operations before income taxes	(1,236,045)	169,733	172,338
Income taxes	(463,660)	54,558	62,459
Income (loss) from discontinued operations	$(772,385)	$115,175	$109,879

Note 3 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2015, were as follows:

	Balance at January 1, 2015 *	Goodwill Acquired During the Year	Balance at 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.

The changes in the carrying amount of goodwill for the year ended December 31, 2014, were as follows:

	Balance at January 1, 2014 *	Goodwill Acquired During the Year/Other	Balance at December 31, 2014 *

	(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	104,276	(835)	103,441
Total	$636,039	$(835)	$ 635,204

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

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Other amortizable intangible assets at December 31 were as follows:

	2015	2014
	(In thousands)	
Customer relationships	$20,975	$21,310
Accumulated amortization	(16,845)	(15,556)
	4,130	5,754
Noncompete agreements	4,409	5,080
Accumulated amortization	(3,655)	(4,098)
	754	982
Other	8,304	10,921
Accumulated amortization	(5,846)	(7,817)
	2,458	3,104
Total	$7,342	$9,840

Amortization expense for amortizable intangible assets for the years ended December 31, 2015, 2014 and 2013, was $2.5 million, $3.2 million and $4.0 million, respectively. Estimated amortization expense for intangible assets is $2.2 million in 2016, $1.9 million in 2017, $1.0 million in 2018, $900,000 in 2019, $300,000 in 2020 and $1.0 million thereafter.

Note 4 - Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period *	2015	2014
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	$185,832	$182,565
Taxes recoverable from customers (a)	Over plant lives	27,682	22,910
Manufactured gas plant sites remediation (a)	Up to 2 years	18,617	17,548
Plant costs (a)	Up to 1 year	8,000	4,551
Natural gas costs recoverable through rate adjustments (b)	Up to 1 year	547	19,575
Long-term debt refinancing costs (a)	Up to 22 years	7,031	7,864
Costs related to identifying generation development (a)	Up to 11 years	3,808	4,165
Other (a) (b)	Largely within 1- 4 years	11,741	10,408
Total regulatory assets		263,258	269,586
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		182,981	338,641
Taxes refundable to customers (c)		17,060	17,772
Natural gas costs refundable through rate adjustments (d)		20,884	13,238
Other (c) (d)		22,193	16,601
Total regulatory liabilities		243,118	386,252
Net regulatory position		$20,140	$(116,666)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.

(a) Included in deferred charges and other assets - other on the Consolidated Balance Sheets.

(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.

(c) Included in other liabilities on the Consolidated Balance Sheets.

(d) Included in other accrued liabilities on the Consolidated Balance Sheets.

(e) Recovered as expense is incurred or cash contributions are made.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. As of December 31, 2015 and 2014, approximately $224.7 million and $229.6 million, respectively, of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

Note 5 - Derivative Instruments

Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. 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. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity.

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

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. The Company had no derivative instruments at December 31, 2015, and as of December 31, 2014, credit risk was not material.

Fidelity

At December 31, 2014, Fidelity held oil swap agreements with total forward notional volumes of 270,000 Bbl and natural gas swap agreements with total forward notional volumes of 5.0 million MMBtu. At 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 gains and losses on the commodity derivative instruments held by Fidelity were included in income (loss) from discontinued operations and the associated assets and liabilities were classified as held for sale.

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

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

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. At December 31, 2015, Centennial had no outstanding interest rate swap agreements.

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Fidelity and Centennial

There were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur, and there were no such reclassifications.

The gains and losses on derivative instruments for the years ended December 31 were as follows:

	2015	2014	2013
		(In thousands)	
Commodity derivatives designated as cash flow hedges:			
Amount of loss recognized in accumulated other comprehensive loss (effective portion), net of tax	$—	$—	$(6,153)
Amount of (gain) loss reclassified from accumulated other comprehensive loss into discontinued operations (effective portion), net of tax	—	295	(4,916)
Amount of loss recognized in operating revenues (ineffective portion), before tax	—	—	(1,422)
Interest rate derivatives designated as cash flow hedges:			
Amount of gain recognized in accumulated other comprehensive loss (effective portion), net of tax	—	—	559
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	404	399	727
Amount of loss recognized in interest expense (ineffective portion), before tax	—	—	(769)
Commodity derivatives not designated as hedging instruments:			
Amount of gain (loss) recognized in discontinued operations, before tax	(18,335)	23,400	(4,845)

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 December 31, 2014
		(In thousands)
Not designated as hedges:		
Commodity derivatives	Current assets held for sale	$18,335
Total asset derivatives		$18,335

All of the Company's commodity derivative instruments at December 31, 2014, 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 (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:

December 31, 2014	Gross Amounts Recognized on the	Gross Amounts Not Offset on the	Net

	Consolidated Balance Sheets (In thousands)	Consolidated Balance Sheets	
Assets:			
Commodity derivatives	$ 18,335	$—	$ 18,335
Total assets	$ 18,335	$—	$ 18,335

Note 6 - 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 $67.5 million and $65.8 million as of December 31, 2015 and 2014, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2015, 2014 and 2013, were $1.7 million, $3.4 million and $13.5 million, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

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

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

December 31, 2014	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$6,594	$60	$(18)	$6,636
U.S. Treasury securities	3,574	—	(19)	3,555
Total	$10,168	$60	$(37)	$10,191

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 period, based on published market quotations on active markets, or using other known sources including pricing from outside sources. Units of these funds can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high-quality, short-term money market instruments that consist of municipal obligations. There are no unfunded commitments related to these funds.

The estimated fair value of the Company's Level 2 mortgage-backed securities and U.S. Treasury securities are based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources.

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

The estimated fair value of the Company's Level 2 RIN obligations are based on the market approach using quoted prices from an independent pricing service. RINs are assigned to biofuels produced or imported into the United States as required by the EPA, which sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the United States. As a producer of diesel fuel, Dakota Prairie Refinery is required to blend biofuels into the fuel it produces at a rate that will meet the EPA's quota. RINs are purchased in the open market to satisfy the requirement as Dakota Prairie Refinery is currently unable to blend biofuels into the diesel fuel it produces.

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 years ended December 31, 2015 and 2014, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 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 December 31, 2015
	(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
Liabilities:				
RIN obligations	$—	$3,052	$—	$3,052
Total liabilities measured at fair value	$—	$3,052	$—	$3,052

* 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.

	Fair Value Measurements at December 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2014
	(In thousands)			
Assets:				
Money market funds	$—	$890	$—	$890
Insurance contract*	—	65,831	—	65,831
Available-for-sale securities:				
Mortgage-backed securities	—	6,636	—	6,636
U.S. Treasury securities	—	3,555	—	3,555
Total assets measured at fair value	$—	$76,912	$—	$76,912

* The insurance contract invests approximately 20 percent in common stock of mid-cap companies, 18 percent in common stock of small-cap companies, 29 percent in common stock of large-cap companies, 32 percent in fixed-income 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 quarters of 2015 and 2013, natural gas gathering assets at the pipeline and midstream segment 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, natural gas gathering assets were written down to the nonrecurring fair value measurement of $1.1 million.

During the third quarter of 2015, the Company was negotiating the sale of certain non-strategic natural gas gathering assets at the pipeline and midstream segment and as a result these assets were found to be impaired and were written down to their estimated fair value using the

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market approach. The estimated fair value of natural gas gathering assets that were impaired at September 30, 2015, was largely determined by agreed upon pricing in a purchase and sale agreement that the Company was negotiating, and these assets were sold in the fourth quarter of 2015. At September 30, 2015, natural gas gathering assets were written down to the nonrecurring fair value measurement of $10.8 million.

The fair value of these natural gas gathering assets have been categorized as Level 3 in the fair value hierarchy.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. For more information on this Level 3 nonrecurring fair value measurement, see Note 2.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. 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 at December 31 was as follows:

	2015		2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$1,871,232	$1,893,442	$2,093,830	$2,238,548

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

Note 7 - Debt

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. 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.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit		Amount Outstanding at December 31, 2015		Amount Outstanding at December 31, 2014		Letters of Credit at December 31, 2015		Expiration Date
		(In millions)								
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$175.0		$ 44.5	(b)	$ 77.5	(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)	$ 47.9		$ 21.0		$ —		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (f)	$650.0		$ 18.0	(b)	$ 211.0	(b)	$ 39.4		5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement	$75.0		$ 45.5		$ —		$ 18.3	(d)	6/30/16

(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.

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The following includes information related to the preceding table.

Short-term borrowings

Dakota Prairie Refining, LLC On September 30, 2015, Dakota Prairie Refining entered into an amendment to its revolving credit agreement which increased the borrowing limit from $50.0 million under the original December 1, 2014, agreement to $75.0 million and extended the termination date from December 1, 2015 to June 30, 2016.

The credit agreement contains customary covenants and provisions, including a covenant of Dakota Prairie Refining and its subsidiaries not to permit, as of the end of any fiscal quarter, the ratio of indebtedness to consolidated capitalization to be greater than 65 percent and a covenant of WBI Holdings and all of its subsidiaries not to permit, as of the end of any fiscal quarter, the ratio of funded debt to capitalization (determined on a consolidated basis) to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness, limitations on distributions and the making of certain investments.

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

Long-term debt

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 credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired; however, there is debt outstanding that is reflected in the following table of long-term debt outstanding. The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain’s total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

Cascade Natural Gas Corporation Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

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

Intermountain Gas Company Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

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

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

Centennial's revolving credit agreement and certain debt outstanding under an expired uncommitted long-term master shelf agreement contain customary covenants and provisions, including a covenant of Centennial, not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent (for the revolving credit agreement) and a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 60 percent (for the master shelf agreement). The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's EBITDA to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include restrictions on the sale of certain assets, limitations on subsidiary indebtedness, minimum consolidated net worth, limitations on priority debt and the making of certain loans and investments.

In December 2015, the lenders under the revolving credit agreement and master shelf agreement provided a waiver and an amendment, respectively, to certain covenants under these agreements removing any potential restrictions related to the disposition of the Fidelity assets.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default.

WBI Energy Transmission, Inc. WBI Energy Transmission has a $175.0 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2015, which reduced capacity under this uncommitted private shelf agreement. This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

Long-term Debt Outstanding Long-term debt outstanding at December 31 was as follows:

	2015	2014
	(In thousands)	
Senior Notes at a weighted average rate of 5.18%, due on dates ranging from February 1, 2016 to January 15, 2055	$1,616,246	$1,636,662
Commercial paper at a weighted average rate of .73%, supported by revolving credit agreements	62,500	288,500
Term Loan Agreements at a weighted average rate of 2.16%, due on dates ranging from April 22, 2018 to April 22, 2023	69,000	72,000
Medium-Term Notes at a weighted average rate of 6.68%, due on dates ranging from September 1, 2020 to March 16, 2029	50,000	35,000
Other notes at a weighted average rate of 5.25%, due on February 1, 2035	24,589	39,662
Credit agreements at a weighted average rate of 1.82%, due on dates ranging from July 14, 2018 to November 30, 2038	48,906	22,042
Discount	(9)	(36)
Total long-term debt	1,871,232	2,093,830

Less current maturities	243,789	268,552
Net long-term debt	$1,627,443	$1,825,278

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2015, aggregate $243.8 million in 2016; $51.0 million in 2017; $175.2 million in 2018; $119.7 million in 2019; $21.0 million in 2020 and $1,260.5 million thereafter.

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Note 8 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution mains and lines, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations as asset retirement obligations.

A reconciliation of the Company's liability, which is included in other accrued liabilities and other liabilities on the Consolidated Balance Sheets, for the years ended December 31 was as follows:

	2015	2014
	(In thousands)	
Balance at beginning of year	$27,211	$27,327
Liabilities incurred	2,751	1,697
Liabilities settled	(1,708)	(3,231)
Accretion expense	1,163	1,112
Revisions in estimates	211,836	(73)
Other	971	379
Balance at end of year	$242,224	$27,211

The 2015 revisions in estimates consist principally of updated natural gas distribution mains and lines asset retirement obligation costs.

The Company believes that largely all expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

Note 9 - Preferred Stocks

Preferred stocks at December 31 were as follows:

	2015	2014
(In thousands, except shares and per share amounts)		
Authorized:		
Preferred -		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A -		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference -		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series - 100,000 shares	$10,000	$10,000
4.70% Series - 50,000 shares	5,000	5,000
Total preferred stocks	$15,000	$15,000

For the years 2015, 2014 and 2013, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or bylaws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year, the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

Note 10 - Common Stock

For the years 2015, 2014 and 2013, dividends declared on common stock were $.7350, $.7150 and $.6950 per common share, respectively.

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From January 2014 through August 2015, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From January 2013 through December 2013, and September 2015 through December 2015, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2015, there were 13.9 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The following discusses the most restrictive limitations.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes, excluding noncash write-downs, for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $1.6 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2015. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $322 million of the Company's (excluding its subsidiaries) net assets, which represents common stockholders' equity including retained earnings, would be restricted from use for dividend payments at December 31, 2015. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 11 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2015, there are 5.6 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy employee performance share awards and purchases shares on the open market for nonemployee director stock awards.

Total stock-based compensation expense (after tax) was $2.9 million, $4.4 million and $3.9 million in 2015, 2014 and 2013, respectively.

As of December 31, 2015, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.6 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 58,181 shares with a fair value of $1.1 million, 43,088 shares with a fair value of $1.1 million and 36,713 shares with a fair value of $1.1 million issued under this plan during the years ended December 31, 2015, 2014 and 2013, respectively.

Performance share awards

Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2015, were as follows:

Grant Date	Performance Period	Target Grant of Shares
March 2013	2013-2015	188,388
February 2014	2014-2016	142,989
February 2015	2015-2017	220,078
June 2015	2015-2017	14,441

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2015, 2014 and 2013 were:

	2015	2014	2013
Weighted average grant-date fair value	$18.98	$41.13	$29.01
Blended volatility range	22.86 %– 24.61 %	18.94 %– 20.43 %	16.10 %– 19.39 %
Risk-free interest rate range	.05 %– 1.07 %	.03 %– .74 %	.09 %– .40 %
Weighted average discounted dividends per share	$1.57	$2.15	$2.12

The fair value of the performance shares that vested during the year ended December 31, 2014, was $16.6 million. There were no performance shares that vested in 2015 and 2013.

A summary of the status of the performance share awards for the year ended December 31, 2015, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	688,455	$28.16
Granted	258,454	18.98
Vested	—	—
Forfeited	(381,013)	22.31
Nonvested at end of period	565,896	$27.90

Note 12 - Income Taxes

The components of income before income taxes from continuing operations for each of the years ended December 31 were as follows:

	2015	2014	2013
		(In thousands)	
United States	$181,623	$242,442	$242,569
Foreign	(1,326)	(52)	416
Income before income taxes from continuing operations	$180,297	$242,390	$242,985

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Income tax expense from continuing operations for the years ended December 31 was as follows:

	2015	2014	2013
		(In thousands)	
Current:			
Federal	$59,483	$4,403	$41,624
State	5,789	(166)	4,148
Foreign	30	—	(29)
	65,302	4,237	45,743
Deferred:			
Income taxes:			
Federal	3,199	55,514	29,616
State	(2,478)	2,467	(859)
Investment tax credit - net	(420)	1,009	(206)
	301	58,990	28,551
Total income tax expense	$65,603	$63,227	$74,294

Components of deferred tax assets and deferred tax liabilities at December 31 were as follows:

	2015	2014
	(In thousands)	
Deferred tax assets:		
Postretirement	$97,666	$99,853
Compensation-related	33,844	35,669
Alternative minimum tax credit carryforward	28,173	23,678
Customer advances	12,623	12,245
Asset retirement obligations	8,694	7,894
Legal and environmental contingencies	6,377	7,890
Other	58,202	52,862
Total deferred tax assets	245,579	240,091
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	791,368	773,160
Postretirement	71,835	70,642
Intangible asset amortization	23,950	22,810
Other	36,906	46,637
Total deferred tax liabilities	924,059	913,249
Valuation allowance	8,990	8,852
Net deferred income tax liability	$(687,470)	$(682,010)

As of December 31, 2015 and 2014, the Company had various state income tax net operating loss carryforwards of $116.2 million and $114.3 million, respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $10.9 million and $7.5 million, respectively. The federal income tax credit carryforwards expire in 2036 if not utilized and state income tax credit carryforwards are due to expire between 2016 and 2032. It is likely that a portion of the benefit from the state carryforwards will not be realized; therefore, valuation allowances have been provided. Changes in tax regulations or assumptions regarding current and future taxable income could require additional valuation allowances in the future. The alternative minimum tax credit carryforwards do not expire. For information regarding net operating loss carryforwards and valuation allowances related to discontinued operations, see Note 2.

The following table reconciles the change in the net deferred income tax liability from December 31, 2014, to December 31, 2015, to deferred income tax expense:

	2015

(In thousands)		
Change in net deferred income tax liability from the preceding table	$5,460	
Deferred taxes associated with other comprehensive income	(3,086	)
Other	(2,073	)
Deferred income tax expense for the period	$301	

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Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	2015		2014		2013	
	Amount	%	Amount	%	Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	$63,104	35.0	$84,836	35.0	$85,045	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	4,903	2.7	7,048	2.9	7,379	3.0
Noncontrolling interest	12,340	6.8	1,363	.5	—	—
Federal renewable energy credit	(3,400)	(1.9)	(3,655)	(1.5)	(3,404)	(1.4)
Tax compliance and uncertain tax positions	(194)	(.1)	(8,987)	(3.7)	(3,902)	(1.6)
Domestic production activities	—	—	(3,993)	(1.6)	(666)	(.3)
Other	(11,150)	(6.1)	(13,385)	(5.5)	(10,158)	(4.1)
Total income tax expense	$65,603	36.4	$63,227	26.1	$74,294	30.6

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $2.4 million at December 31, 2015. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2015, was approximately $900,000.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. The Company is no longer subject to U.S. federal or non-U.S. income tax examinations by tax authorities for years ending prior to 2011. With few exceptions, as of December 31, 2015, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2010.

A reconciliation of the unrecognized tax benefits (excluding interest) for the years ended December 31 was as follows:

	2015	2014	2013
		(In thousands)	
Balance at beginning of year	$105	$7,845	$7,845
Settlements	—	(7,740)	—
Lapse of statute of limitations	(105)	—	—
Balance at end of year	$—	$105	$7,845

At December 31, 2015 and 2014, there were no tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $119,000, including approximately $14,000 for the payment of interest and penalties at December 31, 2014. Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2015, 2014 and 2013, the Company recognized approximately $122,000, $387,000 and $107,000, respectively, of interest expense in income tax expense. For the years ended December 31, 2015, 2014 and 2013, the Company recognized approximately $3.4 million, $1.2 million and $914,000, respectively, in interest expense. Penalties were not material in 2015, 2014 and 2013. The Company recognized interest income of approximately $3.7 million, $469,000 and $655,000 for the years ended December 31, 2015, 2014 and 2013, respectively. At December 31, 2015 and 2014, the Company had accrued liabilities of approximately $94,000 and interest receivable of $367,000, respectively, for the payment or receipt of interest.

Note 13 - 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.

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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, processing and gathering services, as well as oil gathering, through regulated and nonregulated pipeline systems and processing facilities primarily in the Rocky Mountain and northern Great Plains regions of the United States.

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 communication 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 refining segment refines crude oil and produces and sells diesel fuel, naphtha, ATBs and other by-products of the production process. The refining segment includes Dakota Prairie Refinery which is jointly owned by WBI Energy and Calumet and is located in southwestern North Dakota, along with WBI Energy's other activity that supports the refinery.

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 includes certain general and administrative costs (reflected in operation and maintenance expense) and interest expense which were previously allocated to 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 Fidelity other than certain general and administrative costs and interest expense as described above. 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. In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. The completion of the majority of these sales occurred in the fourth quarter of 2015 and the Company continues to market the remaining assets of Fidelity. Discontinued operations also includes legal expenses and a benefit related to the vacation of an arbitration award in 2014 related to Centennial Resources. For more information on discontinued operations, see Note 2.

Part II

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2015	2014	2013
		(In thousands)	
External operating revenues:			
Regulated operations:			
Electric	$280,615	$277,874	$257,260
Natural gas distribution	817,419	921,986	851,945
Pipeline and midstream	50,238	46,786	47,633
	1,148,272	1,246,646	1,156,838
Nonregulated operations:			
Pipeline and midstream	54,282	64,494	56,427
Construction materials and contracting	1,901,530	1,740,089	1,675,444
Construction services	907,767	1,062,055	1,029,909
Refining	178,262	—	—
Other	1,436	1,532	1,553
	3,043,277	2,868,170	2,763,333
Total external operating revenues	$4,191,549	$4,114,816	$3,920,171
Intersegment operating revenues:			
Electric	$—	$—	$—
Natural gas distribution	—	—	—
Pipeline and midstream	51,716	46,085	40,511
Construction materials and contracting	2,752	25,241	36,693
Construction services	18,660	57,474	9,930
Refining	—	—	—
Other	7,755	7,832	8,067
Intersegment eliminations	(80,883)	(136,632)	(95,201)
Total intersegment operating revenues	$—	$—	$—
Depreciation, depletion and amortization:			
Electric	$37,583	$35,008	$32,789
Natural gas distribution	64,756	54,700	50,031
Pipeline and midstream	27,981	29,749	29,105
Construction materials and contracting	65,937	68,557	74,470
Construction services	13,420	12,874	11,939
Refining	16,463	896	14
Other	2,070	2,196	2,050
Intersegment eliminations	(480)	—	—
Total depreciation, depletion and amortization	$227,730	$203,980	$200,398
Interest expense:			
Electric	$17,421	$15,595	$12,590
Natural gas distribution	29,471	27,217	25,123
Pipeline and midstream	9,895	9,946	10,148
Construction materials and contracting	15,183	16,368	17,394
Construction services	3,959	4,176	4,306

Refining	3,450	119	182
Other	14,292	13,739	14,216
Intersegment eliminations	(603)	(254)	(156)
Total interest expense	$93,068	$86,906	$83,803

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	2015	2014	2013
		(In thousands)	
Income taxes:			
Electric	$11,523	$12,442	$9,683
Natural gas distribution	11,377	11,350	16,633
Pipeline and midstream	7,505	12,232	3,466
Construction materials and contracting	41,619	18,586	24,765
Construction services	16,432	24,753	29,504
Refining	(13,815)	(2,533)	(76)
Other	(8,107)	(9,798)	(6,812)
Intersegment eliminations	(931)	(3,805)	(2,869)
Total income taxes	$65,603	$63,227	$74,294
Earnings (loss) on common stock:			
Regulated operations:			
Electric	$35,914	$36,731	$34,837
Natural gas distribution	23,607	30,484	37,656
Pipeline and midstream	20,680	15,440	15,388
	80,201	82,655	87,881
Nonregulated operations:			
Pipeline and midstream	(7,430)	9,226	(7,687)
Construction materials and contracting	89,096	51,510	50,946
Construction services	23,762	54,432	52,213
Refining	(22,457)	(2,038)	(72)
Other	(12,376)	(7,317)	(10,605)
	70,595	105,813	84,795
Intersegment eliminations	(1,531)	(6,095)	(4,307)
Earnings on common stock before income (loss) from discontinued operations	149,265	182,373	168,369
Income (loss) from discontinued operations, net of tax	(772,385)	115,175	109,879
Total earnings (loss) on common stock	$(623,120)	$297,548	$278,248
Capital expenditures:			
Electric	$332,876	$185,121	$168,557
Natural gas distribution	130,793	120,613	101,279
Pipeline and midstream	18,315	61,754	40,533
Construction materials and contracting	48,126	37,896	34,607
Construction services	38,269	26,942	15,102
Refining	22,052	115,655	86,559
Other	3,755	2,131	2,249
Net proceeds from sale or disposition of property and other	(63,831)	(60,177)	(28,392)
Total net capital expenditures	$530,355	$489,935	$420,494
Assets:			
Electric*	$1,327,258	$1,030,611	$884,283
Natural gas distribution*	2,042,925	1,931,908	1,786,068
Pipeline and midstream	593,025	655,735	620,639

Construction materials and contracting	1,279,057	1,272,231	1,305,808
Construction services	450,896	454,602	450,614
Refining	464,699	429,102	178,062
Other**	278,433	306,572	236,543
Assets held for sale	191,315	1,751,647	1,611,430
Total assets	$6,627,608	$7,832,408	$7,073,447

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	2015	2014	2013
		(In thousands)	
Property, plant and equipment:			
Electric*	$1,786,148	$1,457,101	$1,315,822
Natural gas distribution*	2,076,581	1,904,759	1,776,901
Pipeline and midstream	758,729	818,388	789,569
Construction materials and contracting	1,553,428	1,529,942	1,510,355
Construction services	163,279	144,395	134,948
Refining	445,333	401,845	172,603
Other	49,537	50,937	49,997
Eliminations	(15,367)	(12,589)	(4,473)
Less accumulated depreciation, depletion and amortization	2,506,571	2,386,113	2,284,169
Net property, plant and equipment	$4,311,097	$3,908,665	$3,461,553

* Includes allocations of common utility property.

** Includes assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).

Capital expenditures for 2015, 2014 and 2013 include noncash capital expenditure-related accounts payable and exclude capital expenditures of the noncontrolling interest related to Dakota Prairie Refinery. The net transactions were $(40.5) million in 2015, $(88.8) million in 2014 and $(70.0) million in 2013.

Note 14 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

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. At December 31, 2015, all of the Company's defined pension plans have been frozen. These employees will be eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Employees who had attained age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, will not be eligible for retiree medical benefits at certain of the Company's businesses.

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

Part II

Changes in benefit obligation and plan assets for the years ended December 31, 2015 and 2014, and amounts recognized in the Consolidated Balance Sheets at December 31, 2015 and 2014, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$475,337	$402,772	$99,012	$81,726
Service cost	86	129	1,816	1,518
Interest cost	17,141	17,682	3,607	3,521
Plan participants' contributions	—	—	1,408	1,399
Actuarial (gain) loss	(24,875)	80,520	(5,873)	18,024
Benefits paid	(24,729)	(25,766)	(7,236)	(7,176)
Benefit obligation at end of year	442,960	475,337	92,734	99,012
Change in net plan assets:				
Fair value of plan assets at beginning of year	354,363	334,844	87,586	84,543
Actual gain (loss) on plan assets	(10,879)	24,500	258	7,527
Employer contribution	13,912	20,785	577	1,293
Plan participants' contributions	—	—	1,408	1,399
Benefits paid	(24,729)	(25,766)	(7,236)	(7,176)
Fair value of net plan assets at end of year	332,667	354,363	82,593	87,586
Funded status - under	$(110,293)	$(120,974)	$(10,141)	$(11,426)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	$—	$—	$5,095	$4,345
Other accrued liabilities (current)	—	—	(421)	(322)
Other liabilities (noncurrent)	(110,293)	(120,974)	(14,815)	(15,449)
Net amount recognized	$(110,293)	$(120,974)	$(10,141)	$(11,426)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	$208,671	$207,430	$22,484	$25,779
Prior service cost (credit)	—	294	(14,374)	(15,744)
Total	$208,671	$207,724	$8,110	$10,035

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities), see Note 4.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets.

The pension plans all have accumulated benefit obligations in excess of plan assets. The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for these plans at December 31 were as follows:

	2015	2014
	(In thousands)	
Projected benefit obligation	$442,960	$475,337
Accumulated benefit obligation	$442,960	$475,337
Fair value of plan assets	$332,667	$354,363

Part II

Components of net periodic benefit cost (credit) for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
	(In thousands)					
Components of net periodic benefit cost (credit):						
Service cost	$86	$129	$155	$1,816	$1,518	$1,675
Interest cost	17,141	17,682	16,249	3,607	3,521	3,215
Expected return on assets	(22,254)	(21,218)	(19,917)	(4,795)	(4,617)	(4,343)
Amortization of prior service cost (credit)	36	71	71	(1,371)	(1,393)	(1,457)
Recognized net actuarial loss	7,016	4,869	7,173	1,960	649	1,814
Curtailment loss	258	—	—	—	—	—
Net periodic benefit cost (credit), including amount capitalized	2,283	1,533	3,731	1,217	(322)	904
Less amount capitalized	316	388	727	120	(21)	164
Net periodic benefit cost (credit)	1,967	1,145	3,004	1,097	(301)	740
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	8,257	77,238	(60,173)	(1,336)	15,114	(30,461)
Amortization of actuarial loss	(7,016)	(4,869)	(7,173)	(1,960)	(649)	(1,814)
Amortization of prior service (cost) credit	(294)	(71)	(71)	1,371	1,393	1,457
Total recognized in accumulated other comprehensive (income) loss	947	72,298	(67,417)	(1,925)	15,858	(30,818)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss	$2,914	$73,443	$(64,413)	$(828)	$15,557	$(30,078)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 is $6.2 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 are $1.5 million and $1.4 million, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
Discount rate	4.00%	3.70%	4.06%	3.74%
Expected return on plan assets	6.75%	7.00%	5.75%	6.00%
Rate of compensation increase	N/A	N/A	3.00%	3.00%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014

Discount rate	3.70%	4.53%	3.74%	4.48%
Expected return on plan assets	7.00%	7.00%	6.00%	6.00%
Rate of compensation increase	N/A	N/A	3.00%	3.00%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2015, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 30 percent to 40 percent equity securities and 60 percent to 70 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Part II

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2015	2014
Health care trend rate assumed for next year	4.0 %– 8.0 %	4.0 %– 7.0 %
Health care cost trend rate - ultimate	5.0 %– 6.0 %	5.0 %– 6.0 %
Year in which ultimate trend rate achieved	2021	2017

The Company's other postretirement benefit plans include health care and life insurance benefits for certain retirees. The plans underlying these benefits may require contributions by the retiree depending on such retiree's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over six percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2015:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$203	$(169)
Effect on postretirement benefit obligation	$4,006	$(3,407)

The Company's pension assets are managed by 15 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

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 pension plans' assets are determined using the market approach.

The carrying value of the pension plans' Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high quality, short-term instruments of domestic and foreign issuers. There are no unfunded commitments related to this fund.

The estimated fair value of the pension plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources. Units of these funds can be redeemed on a daily basis at their net asset value and have no redemption restrictions. There are no unfunded commitments related to these funds.

The estimated fair value of the pension plans' Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows

and other reference data.
The estimated fair value of the pension plans' Level 1 U.S. Government securities are valued based on quoted prices on an active market.

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The estimated fair value of the pension plans' Level 2 U.S. Government securities are valued mainly using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, to be announced prices, future cash flows and other reference data. Some of these securities are valued using pricing from outside sources.

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 years ended December 31, 2015 and 2014, there were no transfers between Levels 1 and 2.

The fair value of the Company's pension plans' assets (excluding cash) by class were as follows:

	Fair Value Measurements at December 31, 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 December 31, 2015
	(In thousands)			
Assets:				
Cash equivalents	$—	$8,379	$—	$8,379
Equity securities:				
U.S. companies	15,135	—	—	15,135
International companies	2,332	—	—	2,332
Collective and mutual funds*	154,400	63,568	—	217,968
Corporate bonds	—	62,145	—	62,145
Municipal bonds	—	11,680	—	11,680
U.S. Government securities	5,288	6,823	—	12,111
Total assets measured at fair value	$177,155	$152,595	$—	$329,750

* Collective and mutual funds invest approximately 19 percent in common stock of large-cap U.S. companies, 6 percent in common stock of mid-cap U.S. companies, 16 percent in corporate bonds, 29 percent in common stock of international companies, 16 percent in cash equivalents and 14 percent in other investments.

	Fair Value Measurements at December 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2014
	(In thousands)			
Assets:				
Cash equivalents	$—	$5,631	$—	$5,631
Equity securities:				
U.S. companies	39,077	—	—	39,077
International companies	5,189	—	—	5,189
Collective and mutual funds*	132,403	77,449	—	209,852
Corporate bonds	—	59,471	—	59,471

Municipal bonds	—	10,462	—	10,462
U.S. Government securities	15,001	6,849	—	21,850
Total assets measured at fair value	$191,670	$159,862	$—	$351,532

* Collective and mutual funds invest approximately 13 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Government securities, 23 percent in corporate bonds, 33 percent in common stock of international companies and 18 percent in other investments.

The estimated fair values of the Company's other postretirement benefit plans' assets are determined using the market approach.

The estimated fair value of the other postretirement benefit plans' Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in

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high-quality, short-term money market instruments that consist of municipal obligations. There are no unfunded commitments related to this fund.
The estimated fair value of the other postretirement benefit plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.
The estimated fair value of the other postretirement benefit plans' 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 years ended December 31, 2015 and 2014, there were no transfers between Levels 1 and 2.
The fair value of the Company's other postretirement benefit plans' assets (excluding cash) by asset class were as follows:

	Fair Value Measurements at December 31, 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 December 31, 2015
	(In thousands)			
Assets:				
Cash equivalents	$—	$3,261	$—	$3,261
Equity securities:				
U.S. companies	2,274	—	—	2,274
International companies	9	—	—	9
Insurance contract*	—	77,044	—	77,044
Total assets measured at fair value	$2,283	$80,305	$—	$82,588

* The insurance contract invests approximately 19 percent in common stock of large-cap U.S. companies, 22 percent in U.S. Government securities, 10 percent in mortgage-backed securities, 36 percent in corporate bonds and 13 percent in other investments.

	Fair Value Measurements at December 31, 2014, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2014
	(In thousands)			
Assets:				
Cash equivalents	$—	$2,097	$—	$2,097
Equity securities:				
U.S. companies	2,614	—	—	2,614
International companies	25	—	—	25

Insurance contract*	—	82,846	—	82,846
Total assets measured at fair value	$2,639	$84,943	$—	$87,582

* The insurance contract invests approximately 54 percent in common stock of large-cap U.S. companies, 11 percent in U.S. Government securities, 10 percent in mortgage-backed securities, 10 percent in corporate bonds and 15 percent in other investments.

The Company does not expect to contribute to its defined benefit pension plans and expects to contribute approximately $800,000 to its postretirement benefit plans in 2016.

Part II

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2016	$ 24,223	$ 5,234	$ 197
2017	24,680	5,351	191
2018	24,980	5,420	183
2019	25,323	5,441	175
2020	25,700	5,331	168
2021 - 2025	133,029	27,261	688

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, 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 was $7.1 million, $6.6 million and $7.3 million in 2015, 2014 and 2013, respectively. The total projected benefit obligation for these plans was $110.8 million and $115.6 million at December 31, 2015 and 2014, respectively. The accumulated benefit obligation for these plans was $104.6 million and $108.2 million at December 31, 2015 and 2014, respectively. A weighted average discount rate of 3.77 percent and 3.51 percent at December 31, 2015 and 2014, respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent at December 31, 2015 and 2014, were used to determine benefit obligations. A discount rate of 3.51 percent and 4.32 percent for the years ended December 31, 2015 and 2014, respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent for the years ended December 31, 2015 and 2014, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $6.5 million in 2016; $6.7 million in 2017; $7.1 million in 2018; $7.3 million in 2019; $7.8 million in 2020 and $37.7 million for the years 2021 through 2025.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2015, 2014 and 2013 were $207,000, $104,000 and $25,000, respectively.

The Company had investments of $105.2 million and $101.4 million at December 31, 2015 and 2014, respectively, consisting of equity securities of $54.2 million and $54.9 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $34.3 million and $32.8 million, respectively, and other investments of $16.7 million and $13.7 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $36.8 million in 2015, $34.4 million in 2014 and $33.2 million in 2013.

Multiemployer plans

The Company contributes to a number of multiemployer defined benefit pension plans under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the MEPP by one employer may be used to provide benefits to employees of other participating employers
-

If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers

- If the Company chooses to stop participating in some of its MEPPs, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2015 and 2014 is for the plan's year-end at December 31, 2014, and December 31, 2013, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded.

Part II

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2015	2014	FIP/RP Status Pending/Implemented	Contributions 2015	2014	2013	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green as of 12/31/2015	Green as of 12/31/2014	No	$5,517	$9,061	$6,358	No	12/31/2017
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2015	Red as of 6/30/2014	Implemented	2,252	1,392	1,284	No	11/29/2015*
IBEW Local No. 246 Pension Plan	34-6582842-001	Yellow as of 5/31/2015	Yellow as of 5/31/2014	Implemented	433	694	1,848	No	10/31/2017
IBEW Local No. 357 Pension Plan A	88-6023284-001	Green	Green	No	1,896	3,575	2,348	No	5/31/2018
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2015	Red as of 2/28/2014	Implemented	745	1,110	1,489	No	9/2/2018
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2015	Green as of 5/31/2014	No	1,169	1,125	1,121	No	9/30/2016
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2015	Yellow as of 4/30/2014	Implemented	937	568	531	No	6/5/2016
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	Red as of 12/31/2015	Red as of 12/31/2014	Implemented	677	608	583	No	3/31/2016-7/31/2018
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	5,271	6,476	5,883	No	6/30/2015*-11/30/2019
Pension Trust Fund for Operating Engineers	94-6090764-001	Red as of 12/31/2015	Red as of 12/31/2014	Implemented	1,997	1,445	1,510	No	6/15/2015*–6/30/2016
Operating Engineers Local 800 & WY Contractors	83-6011320-001	Red as of 12/31/2015	Red as of 12/31/2014	Implemented	—	68	76	No	10/31/2005*

Association, Inc. Pension Plan for Wyoming**										
Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Red as of 12/31/2013	Red as of 12/31/2014	Implemented	714	676	512	No	6/30/2016
Southwest Marine Pension Trust	95-6123404-001	Red	Red	Implemented	26	31	42	No	1/31/2014*– 1/31/2019
Other funds					17,478	15,988	15,675		
Total contributions					$39,112	$42,817	$39,260		

* Plan includes collective bargaining agreements which have expired. The agreements contain provisions that automatically renew the existing contracts in lieu of a new negotiated collective bargaining agreement.
** The Company withdrew from the plan as of October 26, 2014, as discussed below.

The Company was listed in the plans' Forms 5500 as providing more than 5 percent of the total contributions for the following plans and plan years:

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Edison Pension Plan	2014 and 2013
IBEW Local No. 82 Pension Plan	2014 and 2013
Local Union No. 124 IBEW Pension Trust Fund	2014 and 2013
Local Union 212 IBEW Pension Trust Fund	2014 and 2013
IBEW Local Union No. 357 Pension Plan A	2014 and 2013
IBEW Local 573 Pension Plan	2014
IBEW Local 648 Pension Plan	2014 and 2013
Idaho Plumbers and Pipefitters Pension Plan	2014
Minnesota Teamsters Construction Division Pension Fund	2014 and 2013
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming*	2014 and 2013
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	2014 and 2013

* The Company withdrew from the plan as of October 26, 2014, as discussed below.

On September 24, 2014, Knife River 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 Knife River's withdrawal liability. The Company estimated the withdrawal liability to be approximately $14.0 million at December 31, 2014. In the first quarter of 2015, the Company accrued an additional withdrawal liability of approximately $2.4 million. The total withdrawal liability is currently estimated at $16.4 million. The assessed withdrawal liability for this plan may be significantly different from the current estimate.
The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $31.4 million, $34.6 million and $37.1 million for the years ended December 31, 2015, 2014 and 2013, respectively.
Amounts contributed in 2015, 2014 and 2013 to defined contribution multiemployer plans were $19.5 million, $22.0 million and $20.6 million, respectively.

Note 15 - Jointly Owned Facilities

The consolidated financial statements include the Company's ownership interests in the assets, liabilities and expenses of the Big Stone Station, Coyote Station and Wygen III. Each owner of the stations is responsible for financing its investment in the jointly owned facilities.
The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses (fuel, operation and maintenance and taxes, other than income) in the Consolidated Statements of Income.
At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2015	2014
	(In thousands)	
Big Stone Station:		
Utility plant in service	$157,761	$64,283
Less accumulated depreciation	48,242	43,043
	$109,519	$21,240
Coyote Station:		
Utility plant in service	$140,895	$138,810
Less accumulated depreciation	94,755	94,443
	$46,140	$44,367
Wygen III:		
Utility plant in service	$65,023	$65,597
Less accumulated depreciation	6,788	5,928
	$58,235	$59,669

Note 16 - Regulatory Matters

On March 31, 2015, Cascade filed an application with the OPUC for a natural gas rate increase. Cascade requested a total increase of approximately $3.6 million annually or approximately 5.1 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities and the associated operation and maintenance expenses, depreciation and taxes associated with the increase in investment, as well as environmental remediation expenses. On November 2, 2015, Cascade, staff of the OPUC, the Citizens' Utility Board of Oregon and the Northwest Industrial Gas Users filed a settlement agreement that resolved all issues of the application and reflected a natural gas rate increase of approximately $600,000 annually or approximately .8 percent, to be effective February 1, 2016. The OPUC issued an order on December 28, 2015, accepting the settlement.

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. The increase is necessary 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. Montana-Dakota requested an interim increase of approximately $11.0 million annually. The MTPSC denied the request for interim rates on December 15, 2015. 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. This matter is pending before the MTPSC.

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. The increase is necessary 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. This matter is pending before the SDPUC. An interim increase of $2.7 million, subject to refund, was implemented January 1, 2016. A hearing is scheduled for the week of April 11, 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. The increase is necessary 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. This matter is pending before the SDPUC. An interim increase of $1.5 million, subject to refund, was implemented January 1, 2016. A hearing is scheduled for April 4, 2016.

On September 1, 2015, and as amended on October 5, 2015, Montana-Dakota submitted an update to its transmission formula rate under the MISO tariff including a revenue requirement for the Company's multivalue project of $3.8 million, which was effective January 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. The increase is necessary 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 is scheduled for April 7 and 8, 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. If approved by the NDPSC, the settlement 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 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. An informal hearing with the NDPSC was held January 20, 2016, regarding this matter. The NDPSC approved the filing on February 10, 2016, 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 costs associated with increased infrastructure investment and the associated operating expenses. The filing is pending before the WUTC. The natural gas rate increase is expected to be effective November 1, 2016. A hearing on this matter has been scheduled to begin August 2, 2016.

Note 17 - Commitments and 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 $19.5 million and $27.6 million, which include liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at December 31, 2015 and 2014, respectively, including amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel WBI Energy Midstream to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of WBI Energy Midstream's pipeline gathering systems in Montana. WBI Energy Midstream resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered WBI Energy Midstream into arbitration. In October 2010, the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. The Colorado Court of Appeals issued a decision on May 24, 2012, reversing the Colorado State District Court order compelling arbitration, vacating the final award and remanding the case to the Colorado State District Court to determine SourceGas's claims and WBI Energy Midstream's counterclaims. WBI Energy Midstream resolved this matter in December 2015 through a settlement that included dismissal of the litigation and payment of an amount that was not material.

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

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

Construction Materials Until the fall of 2011 when it discontinued active mining operations at the pit, JTL operated the Target Range Gravel Pit in Missoula County, Montana under a 1975 reclamation contract pursuant to the Montana Opencut Mining Act. In September 2009, the Montana DEQ sent a letter asserting JTL was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL filed a complaint in

Montana First Judicial District Court in June 2010, seeking a declaratory order that the reclamation contract is a valid permit under the Montana Opencut Mining Act. The Montana DEQ filed an answer and counterclaim to the complaint in August 2011, alleging JTL was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than $3.7 million plus not more than $5,000 per day from the date of the counterclaim. The Company believes the operation of the Target Range Gravel Pit was conducted under a valid permit; however, the imposition of civil penalties is reasonably possible. The Company filed an application for amendment of its opencut mining permit which JTL expects will be approved by the Montana DEQ in the first half of 2016. The Company intends to resolve the Montana First Judicial District Court litigation through settlement.

Construction Services Bombard Mechanical is a third-party defendant in litigation pending in Nevada State District Court in which the plaintiff 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. Bombard Mechanical is being defended in the action under a policy of insurance subject to a reservation of rights.

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

Environmental matters

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

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

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

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 intends to request a contested case hearing on the Notice of Civil Penalty.

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 Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.9 million for the remedial investigation, feasibility study and remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers. The accruals related to these matters are reflected in regulatory assets. For more information, see Note 4.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2015, were $52.3 million in 2016, $42.7 million in 2017, $35.5 million in 2018, $26.4 million in 2019, $15.9 million in 2020 and $76.9 million thereafter. Rent expense was $65.1 million, $48.5 million and $39.7 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Purchase commitments

The Company has entered into various commitments, largely construction, natural gas and coal supply, purchased power, natural gas transportation and storage, and service, shipping and construction materials supply contracts, some of which are subject to variability in volume and price. These commitments range from one to 45 years. The commitments under these contracts as of December 31, 2015, were $443.7 million in 2016, $228.0 million in 2017, $138.9 million in 2018, $112.9 million in 2019, $90.4 million in 2020 and $853.9 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2015, 2014 and 2013, were $861.4 million, $925.2 million and $860.5 million, respectively.

Guarantees

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

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 December 31, 2015, the fixed maximum amounts guaranteed under these agreements aggregated $128.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $33.1 million in 2016; $35.0 million in 2017; $600,000 in 2018; $54.9 million in 2019; $1.0 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2015. 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 December 31, 2015, the fixed maximum amounts guaranteed under these letters of credit aggregated $57.3 million, all of which expire in 2016. The amount outstanding by subsidiaries of the Company under the above letters of credit was $4.1 million and was reflected on the Consolidated Balance Sheet at December 31, 2015. 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.

Centennial and WBI Holdings have guaranteed certain debt obligations of Dakota Prairie Refining. For more information, see Variable interest entities in this note.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2015.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2015, approximately $530.0 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. For more information, see Note 1.

Dakota Prairie Refining, LLC On February 7, 2013, WBI Energy and Calumet formed a limited liability company, Dakota Prairie Refining, and entered into an operating agreement to develop, build and operate Dakota Prairie Refinery in southwestern North Dakota. WBI Energy and Calumet each have a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of $300 million, under the agreement are $150 million and $75 million, respectively. Capital commitments in excess of $300 million are being shared equally between WBI Energy and Calumet. WBI Energy's and Calumet's cumulative capital contributions, net of distributions, as of December 31, 2015, are $230.4 million and $163.6 million, respectively. Dakota Prairie Refining entered into a term loan for project debt financing of $75 million on April 22, 2013. The operating agreement provides for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt will be allocated to Calumet. Calumet's future cash distributions from Dakota Prairie Refining will be decreased by the principal and interest to be paid on the project debt, while the cash distributions to WBI Energy will not be decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan. The net loss attributable to noncontrolling interest on the Consolidated Statements of Income is pretax as Dakota Prairie Refining is a limited liability company.

On September 30, 2015, Dakota Prairie Refining entered into an amendment to its revolving credit agreement which increased the borrowing limit from $50.0 million under the original December 1, 2014, agreement to $75.0 million and extended the termination date from December 1, 2015 to June 30, 2016. Centennial and Calumet have each issued a letter of credit supporting 50 percent of the credit agreement. The credit agreement is used to meet the operational needs of the facility.

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

Part II

Dakota Prairie Refinery has commenced operations. The assets of Dakota Prairie Refining shall be used solely for the benefit of Dakota Prairie Refining. The total assets and liabilities of Dakota Prairie Refining reflected on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2015	2014
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$851	$21,376
Accounts receivable	7,693	2,759
Inventories	13,176	5,311
Other current assets	6,215	4,019
Total current assets	27,935	33,465
Net property, plant and equipment	425,123	398,984
Deferred charges and other assets:		
Other	9,626	3,400
Total deferred charges and other assets	9,626	3,400
Total assets	$462,684	$435,849
Liabilities		
Current liabilities:		
Short-term borrowings	$45,500	$—
Long-term debt due within one year	5,250	3,000
Accounts payable	24,766	55,089
Taxes payable	1,391	648
Accrued compensation	938	727
Other accrued liabilities	4,953	899
Total current liabilities	82,798	60,363
Long-term debt	63,750	69,000
Total liabilities	$146,548	$129,363

Fuel Contract On October 10, 2012, the Coyote Station entered into a new coal supply agreement with Coyote Creek that will replace a coal supply agreement expiring in May 2016. The new agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040. The new coal supply agreement creates a variable interest in Coyote Creek due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that 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 December 31, 2015, Coyote Creek was not yet operational. The assets and liabilities of Coyote Creek and exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage, at December 31, 2015, was $40.1 million.

Part II

Supplementary Financial Information
Quarterly Data (Unaudited)
The following unaudited information shows selected items by quarter for the years 2015 and 2014:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2015				
Operating revenues	$862,349	$986,215	$1,280,500	$1,062,485
Operating expenses	818,680	940,887	1,170,757	1,007,092
Operating income	43,669	45,328	109,743	55,393
Income from continuing operations	15,160	14,057	53,400	32,077
Income (loss) from discontinued operations, net of tax	(324,605)	(251,415)	(202,626)	6,261
Net income (loss) attributable to the Company	(305,917)	(229,604)	(139,448)	52,534
Earnings (loss) per common share - basic:				
Earnings before discontinued operations	.10	.11	.32	.24
Discontinued operations, net of tax	(1.67)	(1.29)	(1.04)	.03
Earnings (loss) per common share - basic	(1.57)	(1.18)	(.72)	.27
Earnings (loss) per common share - diluted:				
Earnings before discontinued operations	.10	.11	.32	.24
Discontinued operations, net of tax	(1.67)	(1.29)	(1.04)	.03
Earnings (loss) per common share - diluted	(1.57)	(1.18)	(.72)	.27
Weighted average common shares outstanding:				
Basic	194,479	194,805	195,151	195,266
Diluted	194,566	194,838	195,169	195,324
2014				
Operating revenues	$900,761	$952,564	$1,213,203	$1,048,288
Operating expenses	837,153	890,210	1,094,310	973,720
Operating income	63,608	62,354	118,893	74,568
Income from continuing operations	31,027	29,446	63,639	55,051
Income from discontinued operations, net of tax	25,112	23,881	38,482	27,700
Net income attributable to the Company	56,662	54,106	103,209	84,256
Earnings per common share - basic:				
Earnings before discontinued operations	.17	.16	.33	.29
Discontinued operations, net of tax	.13	.12	.20	.14
Earnings per common share - basic	.30	.28	.53	.43
Earnings per common share - diluted:				
Earnings before discontinued operations	.16	.16	.33	.29
Discontinued operations, net of tax	.14	.12	.20	.14
Earnings per common share - diluted	.30	.28	.53	.43
Weighted average common shares outstanding:				
Basic	189,820	192,060	193,949	194,136
Diluted	190,432	192,659	194,300	194,219

Notes:

- First quarter 2015 reflects a MEPP withdrawal liability of $2.4 million (before tax). For more information, see Note 14.
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- Second quarter 2015 reflects an impairment of coalbed natural gas gathering assets of $3.0 million (before tax). For more information, see Note 1.
- Third quarter 2015 reflects an impairment of coalbed natural gas gathering assets of $14.1 million (before tax). For more information, see Note 1.
- Fourth quarter 2014 reflects a MEPP withdrawal liability of approximately $14.0 million (before tax). For more information, see Note 14.
- 2014 and first quarter 2015 have been restated to present the results of operations of Fidelity as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former exploration and production segment and do not meet the criteria for income (loss) from discontinued operations.

Certain Company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

Exploration and Production Activities (Unaudited)

In the third and fourth quarters of 2015 and the first quarter of 2016, the Company entered into purchase and sale agreements to sell the vast majority of Fidelity's assets, comprising greater than 93 percent of total production for 2014. A majority of the sales were completed in the fourth quarter of 2015. At the time the Company committed to a plan to sell Fidelity, the Company stopped the use of the full-cost method of accounting for its oil and natural gas production activities. The assets and liabilities have been classified as held for sale and the results of operations included in income (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. Prior to the asset sales, Fidelity was significantly involved in the development and production of oil and natural gas resources. For more information, see Note 2.

Fidelity shares revenues and expenses from the development of specified properties in proportion to its ownership interests. The information that follows includes Fidelity's proportionate share of all its oil and natural gas interests.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to oil and natural gas producing activities at December 31:

	2015	*2014	2013
	(In thousands)		
Subject to amortization	$—	$3,205,036	$2,893,010
Not subject to amortization	—	132,141	124,869
Total capitalized costs	—	3,337,177	3,017,879
Less accumulated depreciation, depletion and amortization	—	1,752,566	1,562,116
Net capitalized costs	$—	$1,584,611	$1,455,763

* Excludes assets held for sale.

Capital expenditures, including those not subject to amortization, related to oil and natural gas producing activities were as follows:

Years ended December 31,	2015	*2014	**2013	**
	(In thousands)			
Acquisitions:				
Proved properties	$—	$87,919	$1,817	
Unproved properties	—	138,683	4,608	
Exploration	—	16,879	26,975	
Development	—	331,400	355,421	
Total capital expenditures	$—	$574,881	$388,821	

* No wells were drilled in 2015.

** Excludes net additions/(reductions) to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of oil and natural gas wells of $(9.0) million and $(10.7) million for the years ended December 31, 2014 and 2013, respectively.

The preceding table excludes proceeds from the sales of oil and natural gas properties of $246.6 million and $83.6 million for the years ended December 31, 2014 and 2013, respectively.

The following reflects the results of operations from the Company's oil and natural gas producing activities included in discontinued operations, excluding corporate overhead and financing costs:

Years ended December 31,	2015	2014	2013
		(In thousands)	
Income (loss) from discontinued operations	$(772,385)	$111,998	$110,191

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The proved reserve estimates as of December 31, 2015, 2014 and 2013, were calculated using SEC Defined Prices. Other factors used in the proved reserve estimates are current estimates of well operating and future development costs (which include asset retirement costs), taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

The reserve estimates are prepared by internal engineers assigned to an asset team by geographic area. Senior management reviews and approves the reserve estimates to ensure they are materially accurate.

Part II

Estimates of economically recoverable oil, NGL and natural gas reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2015, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	43,918	7,187	245,011	91,940
Production	(3,286)	(393)	(16,747)	(6,471)
Extensions and discoveries	744	29	681	888
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(16,474)	(6,864)	(202,560)	(57,097)
Revisions of previous estimates	(12,215)	252	(23,854)	(15,939)
Balance at end of year	12,687	211	2,531	13,321

Significant changes in proved reserves for the year ended December 31, 2015, include:

- Sales of proved reserves of (57.1) MMBOE, primarily due to the Company's decision to sell Fidelity and exit the exploration and production business
- Revisions of previous estimates of (15.9) MMBOE, largely the result of lower commodity prices

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2014, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	41,019	6,602	198,445	80,695
Production	(4,919)	(609)	(20,822)	(8,998)
Extensions and discoveries	9,654	3,634	64,420	24,025
Improved recovery	—	—	—	—
Purchases of proved reserves	5,463	—	7,711	6,748
Sales of proved reserves	(4,945)	(3,109)	(40,451)	(14,796)
Revisions of previous estimates	(2,354)	669	35,708	4,266
Balance at end of year	43,918	7,187	245,011	91,940

Significant changes in proved reserves for the year ended December 31, 2014, include:

- Extensions and discoveries of 24.0 MMBOE, primarily due to drilling activity at the Company's East Texas, Bakken and Powder River Basin properties
- Purchases of proved reserves of 6.7 MMBOE, primarily due to the purchase of working interests and leasehold positions in the Powder River Basin
- Sales of proved reserves of (14.8) MMBOE, primarily at the Company's South Texas and Bakken properties
- Revisions of previous estimates of 4.3 MMBOE, largely the result of higher natural gas prices and well performance revisions

Part II

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2013, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	33,453	7,153	239,278	80,486
Production	(4,815)	(781)	(28,008)	(10,264)
Extensions and discoveries	13,313	1,333	26,428	19,050
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(1,286)	(25)	(40,055)	(7,987)
Revisions of previous estimates	354	(1,078)	802	(590)
Balance at end of year	41,019	6,602	198,445	80,695

Significant changes in proved reserves for the year ended December 31, 2013, include:

- Extensions and discoveries of 19.1 MMBOE, primarily due to drilling activity and new PUD locations at the Company's Bakken and Paradox Basin properties, as well as new PUD locations at Big Horn and East Texas
- Sales of proved reserves of (8.0) MMBOE, primarily at the Company's Green River Basin property

The following table summarizes the breakdown of the Company's proved reserves between proved developed and PUD reserves at December 31:

	2015	2014	2013
Proved developed reserves:			
Oil (MBbls)	11,380	30,130	31,394
NGL (MBbls)	144	4,217	5,322
Natural Gas (MMcf)	2,033	184,437	176,546
Total (MBOE)	11,865	65,086	66,140
PUD reserves:			
Oil (MBbls)	1,307	13,788	9,625
NGL (MBbls)	67	2,970	1,280
Natural Gas (MMcf)	498	60,574	21,899
Total (MBOE)	1,456	26,854	14,555
Total proved reserves:			
Oil (MBbls)	12,687	43,918	41,019
NGL (MBbls)	211	7,187	6,602
Natural Gas (MMcf)	2,531	245,011	198,445
Total (MBOE)	13,321	91,940	80,695

As of December 31, 2015, the Company had 1.5 MMBOE of PUD reserves, which is a decrease of 25.4 MMBOE from December 31, 2014. The decrease relates to the various asset sales during 2015 and certain PUD reserves becoming uneconomic due to lower commodity prices. At December 31, 2015, the Company did not have any PUD locations that remained undeveloped for five years of more.

Part II

The standardized measure of the Company's estimated discounted future net cash flows of total proved reserves associated with its various oil and natural gas interests at December 31 was as follows:

	2014	2013
	(In thousands)	
Future cash inflows	$5,185,500	$4,507,000
Future production costs	1,856,900	1,734,800
Future development costs	570,200	403,000
Future net cash flows before income taxes	2,758,400	2,369,200
Future income tax expense	686,100	545,200
Future net cash flows	2,072,300	1,824,000
10% annual discount for estimated timing of cash flows	997,400	810,000
Discounted future net cash flows relating to proved oil, NGL and natural gas reserves	$1,074,900	$1,014,000

Note: Standardized measure not applicable in 2015 as the remaining oil and natural gas properties are held for sale and subject to fair value impairment.

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

	2014	2013
	(In thousands)	
Beginning of year	$1,014,000	$883,400
Net revenues from production	(368,900)	(398,000)
Net change in sales prices and production costs related to future production	86,300	162,200
Extensions and discoveries, net of future production-related costs	231,900	366,500
Improved recovery, net of future production-related costs	—	—
Purchases of proved reserves, net of future production-related costs	103,800	—
Sales of proved reserves	(219,300)	(37,800)
Changes in estimated future development costs	65,100	6,700
Development costs incurred during the current year	104,600	141,500
Accretion of discount	109,400	94,600
Net change in income taxes	(33,400)	(141,400)
Revisions of previous estimates	(16,300)	(55,800)
Other	(2,300)	(7,900)
Net change	60,900	130,600
End of year	$1,074,900	$1,014,000

Note: Standardized measure not applicable in 2015 as the remaining oil and natural gas properties are held for sale and subject to fair value impairment.

Historically, the estimated discounted future cash inflows from estimated future production of proved reserves were computed using prices as previously discussed. Future production and development costs, which include asset retirement costs, attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying statutory tax rates to the estimated net future pretax cash flows less the tax basis of the oil and gas properties, adjusted for permanent differences and tax credits.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of oil and natural gas properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs.

Part II

Definitions

The following abbreviations and acronyms used in Notes to Consolidated Financial Statements are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
Bbl	Barrel
Bicent	Bicent Power LLC
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
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
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Colorado Court of Appeals	Court of Appeals, State of Colorado
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
ESCP	Erosion and Sediment Control Plan
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
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IBEW	International Brotherhood of Electrical Workers
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
LTM	LTM, Incorporated, an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE

Part II

Mcf	Thousand cubic feet
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
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBOE	Millions of BOE
MMBtu	Million Btu
MMcf	Million cubic feet
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
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
PUD	Proved undeveloped
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
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
United States District Court for the District of Montana	United States District Court for the District of Montana, Great Falls Division
VIE	Variable interest entity
WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings

WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

Part II

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. 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 December 31, 2015, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The information required by this item is included in this Form 10-K at Item 8 - Management's Report on Internal Control Over Financial Reporting.

Attestation Report of the Registered Public Accounting Firm

The information required by this item is included in this Form 10-K at Item 8 - Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is included in the last sentence of the second paragraph under the caption "Item 1. Election of Directors" and under the captions "Item 1. Election of Directors - Director Nominees," "Information Concerning Executive Officers," the first paragraph and the second and third sentences of the second paragraph under "Corporate Governance - Audit Committee," "Corporate Governance - Code of Conduct," the second sentence of the last paragraph under "Corporate Governance - Board Meetings and Committees" and "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement, which information is incorporated herein by reference.

Item 11. Executive Compensation

The information required by this item is included under the caption "Executive Compensation" in the Proxy Statement, which information is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is included in the Proxy Statement under the caption "Equity Compensation Plan Information" in Item 2. Approval of the Material Terms of the Performance Goals under the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan for Purposes of Internal Revenue Code Section 162(m) and under the caption "Security Ownership", which information is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is included under the captions "Related Person Transaction Disclosure," "Corporate Governance - Director Independence" and the second sentence of the third paragraph under "Corporate Governance - Board Meetings and Committees" in the Proxy Statement, which information is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by this item is included under the caption "Item 3. Ratification of Independent Registered Public Accounting Firm - Accounting and Auditing Matters" in the Proxy Statement, which information is incorporated herein by reference.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

2. Financial Statement Schedules