MDU RESOURCES GROUP INC

FORM 10-K
(Annual Report)

Filed 02/20/15 for the Period Ending 12/31/14

Address	1200 WEST CENTURY AVENUE BISMARCK, ND 58503
Telephone	701-530-1059
CIK	0000067716
Symbol	MDU
SIC Code	1400 - Mining & Quarrying of Nonmetallic Minerals (No Fuels)
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014

OR

☐ 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 ☒ No ☐ .

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 ☐ No ☒ .

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 ☒ No ☐ .

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 ☒ No ☐ .

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. ☒

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 ☒ Accelerated filer ☐ Non-accelerated filer ☐ Small reporting company ☐
(Do not check if a smaller reporting company)

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

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2014 : $6,795,350,628 .

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 13, 2015 : 194,420,095 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2015 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

Part IV

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
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)
BLM	Bureau of Land Management
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
BOPD	Barrels of oil per day
Brazilian Transmission Lines	Company's investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and portions of the ownership interest in ECTE were sold in the first quarter of 2015, the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010)
Btu	British thermal unit
California Superior Court	Superior Court of the State of California, County of Los Angeles (South District - Long Beach)
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
Connolly-Pacific	Connolly-Pacific Co., an indirect wholly owned subsidiary of Knife River
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant being built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (2.5 percent ownership interest at December 31, 2014, 2.5, 2.5, 2.5 and 14.99 percent ownership interests were sold in the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010, respectively, with the remaining 2.5 percent ownership interest sold in January 2015)
EIN	Employer Identification Number
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
ESA	Endangered Species Act

Definitions

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
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
GVTC	Generation Verification Test Capacity
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
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
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 Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
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
NEPA	National Environmental Policy Act
NGL	Natural gas liquids
NSPS	New Source Performance Standards
NYMEX	New York Mercantile Exchange
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
PDP	Proved developed producing
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2015 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
Ryder Scott	Ryder Scott Company, L.P.
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended
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
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
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
ZRCs	Zonal resource credits - a MW of demand equivalent assigned to generators by MISO for meeting system reliability requirements

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 (comprised of the pipeline and energy services and the exploration and production segments), Knife River (construction materials and contracting segment), MDU Construction Services (construction services segment), Centennial Resources and Centennial Capital (both reflected in the Other category).

The Company's investment in ECTE is reflected in the Other category. For more information, see Item 8 - Note 4 .

As of December 31, 2014 , the Company had 8,451 employees with 163 employed at MDU Resources Group, Inc., 1,030 at Montana-Dakota, 34 at Great Plains, 313 at Cascade, 225 at Intermountain, 586 at WBI Holdings, 2,508 at Knife River and 3,592 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, 2014 .

At Montana-Dakota and WBI Energy Transmission, 349 and 78 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2015, and March 31, 2018, for Montana-Dakota and WBI Energy Transmission, respectively.

At Cascade, 139 employees are represented by the ICWU. The labor contract with the field operations group is effective through April 1, 2015.

At Intermountain, 117 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 460 of its construction materials employees. Knife River is in negotiations on 4 of its labor contracts.

MDU Construction Services has 134 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 15 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 19 . 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 oil and natural gas exploration and development 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 138,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2014 . The principal properties owned by Montana-Dakota for use in its electric operations include interests in 11 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 58 transmission and 279 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, 2014 , Montana-Dakota's net electric plant investment was $960.8 million.

The percentage of Montana-Dakota's 2014 retail electric utility operating revenues by jurisdiction is as follows: North Dakota - 64 percent; Montana - 21 percent; Wyoming - 10 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 582,083 kW in January 2014. The maximum summer electric peak demand experienced to date was 573,587 kW in July 2012. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will occur during the summer and the sales growth rate through 2019 will approximate 6 percent annually. The interconnected system consists of ten electric generating facilities and three small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 577,943 kW and total net ZRCs of 444.8 in 2014 . ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet supply obligations within MISO. For 2014 , Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 584.0. Montana-Dakota's peak demand supply obligation, including firm purchase power contracts, within MISO was 522.4 ZRCs for 2014 . Montana-Dakota's four principal generating stations are steam-turbine generating units using coal for fuel. The nameplate rating for Montana-Dakota's ownership interest in these four stations (including interests in the Big Stone Station and the Coyote Station) is 327,758 kW. Three combustion turbine peaking stations, two wind electric generating facilities, a heat recovery electric generating facility and three small portable diesel generators supply the balance of Montana-Dakota's interconnected system electric generating capability.

Montana-Dakota has a contract for capacity of 120 MW for the period June 1, 2014 to May 31, 2015. On November 20, 2014, Montana-Dakota entered into an asset purchase agreement with Thunder Spirit Wind, LLC, to purchase for approximately $200 million a wind farm of 107.5 MW of installed capacity to be located in southwest North Dakota upon commercial operation subject to regulatory approval. Montana-Dakota has applied for an advance determination of prudence and a certificate of public convenience and necessity from the NDPSC for purchase of the wind farm. If Montana-Dakota does not receive regulatory approval for the purchase of the wind farm, it will purchase the output of the wind farm from Thunder Spirit Wind, LLC under a power purchase agreement. The project is expected to begin commercial operation in the fourth quarter of 2015. The generation will interconnect at Montana-Dakota's substation near Hettinger, North Dakota. Additional energy will be purchased as needed, or if more economical, from the MISO market. In 2014 , Montana-Dakota purchased approximately 29 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.

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

Generating Station	Type	Nameplate Rating (kW)	2014 ZRCs (a)	2014 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	93.2	682,333
Heskett	Steam	86,000	89.0	547,268
Heskett	Combustion Turbine	89,038	(c)	28,057
Glen Ullin	Heat Recovery	7,500	4.4	31,441
Cedar Hills	Wind	19,500	3.7	59,420
Diesel Units	Oil	5,475	4.6	40
South Dakota:				
Big Stone (b)	Steam	94,111	101.3	576,957
Montana:				
Lewis & Clark	Steam	44,000	52.0	290,193
Glendive	Combustion Turbine	75,522	72.1	1,911
Miles City	Combustion Turbine	23,150	19.9	365
Diamond Willow	Wind	30,000	4.6	96,534
		577,943	444.8	2,314,519
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	205,419
		605,943	444.8	2,519,938

(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, April 2016 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.

Montana-Dakota has 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 19 .

Montana-Dakota has coal supply agreements, which meet a portion of the Big Stone Station's fuel requirements, for the purchase of 1.0 million tons in 2015 and 500,000 tons in 2016 from Peabody Coalsales, LLC 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.

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,	**2014**	2013	2012
Average cost of coal per MMBtu	**$ 1.74**	$ 1.73	$ 1.69
Average cost of coal per ton	**$ 25.11**	$ 25.32	$ 24.77

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-2016. 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 within a period ranging from 14 to 25 months from the time such costs are paid. For more information, see Item 8 - Note 6 .

In North Dakota, Montana-Dakota recovers in rates the costs associated with environmental upgrades at Big Stone 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. On January 9, 2015, Montana-Dakota implemented a generation resource recovery rider to recover the costs associated with the Heskett natural gas combustion turbine which was commissioned in August 2014. Montana-Dakota will utilize this rider mechanism for new generation until such time as the costs and investment are included in base rates. 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.

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 Department of Environment and Natural Resources in November 2013. The Title V Operating Permit renewal application for Lewis & Clark Station was submitted timely in February 2014 to the Montana DEQ and the Title V Operating Permit renewal application for Heskett Station was submitted timely in August 2014 to the North Dakota Department of Health. The Montana DEQ issued a Montana Air Quality Permit in January 2015 to Montana-Dakota for the addition of two 9.3 MW engines and associated operating equipment at Lewis & Clark Station.

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 $28.3 million of environmental capital expenditures in 2014 , largely for the installation of a BART air quality control system at the Big Stone Station. Capital expenditures are estimated to be $42 million, $7 million and $2 million in 2015 , 2016 and 2017 , respectively, to maintain environmental compliance as new emission controls are required, including the installation of a BART air quality control system, as discussed above. Projects for 2015 through 2017 also include sulfur-dioxide, nitrogen oxide and mercury and non-mercury metals control equipment installation at electric generating stations and anticipated costs for coal ash disposal. Montana-Dakota's capital and operational expenditures could also be affected in a variety of ways by future air and wastewater effluent discharge regulation, as well as potential new GHG legislation or regulation. In particular, such GHG legislation or regulation would likely increase capital expenditures and operational costs associated with GHG emissions compliance until carbon capture technology becomes economical, at which time capital expenditures may be necessary to incorporate such technology into existing or new generating facilities. Montana-Dakota expects that it will recover the operational and capital expenditures for GHG regulatory compliance in its rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

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 892,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states as of December 31, 2014 , and provide natural gas transportation services to certain customers on their systems. These services are provided through distribution systems aggregating approximately 18,800 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, 2014 , the natural gas distribution operations' net natural gas distribution plant investment was $1.2 billion.

The percentage of the natural gas distribution operations' 2014 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho - 29 percent; Washington - 25 percent; North Dakota - 16 percent; Montana - 9 percent; Oregon - 8 percent; South Dakota - 7 percent; Minnesota - 4 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.

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 within a period ranging from 12 to 28 months.

Montana-Dakota's North Dakota and South Dakota natural gas tariffs contain weather normalization mechanisms applicable to firm customers that adjust the distribution delivery charge revenues to reflect weather fluctuations during the November 1 through May 1 billing periods.

On March 13, 2013, the OPUC approved an extension of Cascade's decoupling mechanism until December 31, 2015. 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 18 .

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 2014 . 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 2017 .

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 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 19 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 Energy Services

General WBI Energy owns and operates both regulated and nonregulated businesses. The regulated business of this segment, WBI Energy Transmission, owns and operates approximately 3,800 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, 2014 , its net plant investment was $358.8 million.

The nonregulated business of this segment owns and operates gathering facilities in Colorado, Montana and Wyoming. It also owns a 50 percent undivided interest in the Pronghorn assets located in western North Dakota that were acquired in 2012, 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 1,600 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.

WBI Energy, in conjunction with Calumet, formed Dakota Prairie Refining, to develop, build and operate Dakota Prairie Refinery. Construction began on the facility in late March 2013 and, when complete, it will process Bakken crude oil into diesel, which will be marketed within the Bakken region. Other by-products, naptha and atmospheric tower bottoms, are expected to be railed to other areas. Total project costs are estimated to be more than $400 million , with a projected in-service date in the second quarter of 2015.

This segment also includes an energy services business which provides natural gas purchase and sales services to local distribution companies, producers, other marketers and a limited number of large end-users, primarily using natural gas produced by Fidelity. Certain of the services are provided based on contracts that call for a determinable quantity of natural gas. At December 31, 2014 , it has commitments to deliver fixed and determinable amounts of natural gas under these contracts of 1.6 MMdk in 2015 . The Company currently estimates that it can adequately meet the requirements of these contracts based upon the estimated natural gas production and reserves of Fidelity.

A majority of its pipeline and energy services 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 19 .

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. The Powder River Basin also provides a nontraditional natural gas supply to the WBI Energy Transmission system. 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 2014 represented 46 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, for the expansion of its systems and for 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 energy services 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 NEPA, ESA 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 are included in the FERC's permitting processes for both the construction and abandonment of WBI Energy Transmission's natural gas transmission pipelines, compressor stations and storage facilities.

The pipeline and energy services operations did not incur any material environmental expenditures in 2014 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2017 .

Exploration and Production

General Fidelity is involved in the development and production of oil and natural gas resources. The Company intends to market its exploration and production business in the future. The plan to market this business has been delayed due to low oil prices. Until such sale is accomplished, this segment will apply technology and utilize existing expertise to increase production and reserves from existing leaseholds. By optimizing existing operations, this segment is focused on balancing its oil and natural gas commodity mix to maximize profitability. Fidelity shares revenues and expenses from the development of specified properties in proportion to its ownership interests.

For information regarding exploration and production litigation, see Item 8 - Note 19 .

Fidelity's business is focused primarily in two core regions: Rocky Mountain and Mid-Continent/Gulf States.

Rocky Mountain

Fidelity's Rocky Mountain region includes the following significant operating areas:

- Bakken areas - Oil targets in which Fidelity holds approximately 12,000 net acres in Mountrail County, North Dakota and approximately 37,000 net acres in Stark County, North Dakota.
- Cedar Creek Anticline - Primarily in eastern Montana, the Company has a long-held net profits interest in this oil play.
- Paradox Basin - The Company holds approximately 140,000 net acres located in Grand and San Juan Counties, Utah, targeting oil, and has an option to earn another 20,000 acres.
- Powder River Basin - The Company holds primarily non-operated undeveloped leasehold positions of approximately 24,000 net acres in Converse County, Wyoming, which were acquired in 2014.
- Big Horn Basin - These interests include approximately 6,000 net acres in Wyoming, targeting oil and NGL.
- Baker Field - Long-held natural gas properties in which Fidelity holds approximately 98,000 net acres in southeastern Montana and southwestern North Dakota.
- Bowdoin Field - Long-held natural gas properties in which Fidelity holds approximately 127,000 net acres in north-central Montana.
- Other - Includes other oil projects and various non-operated positions.

Mid-Continent/Gulf States

Fidelity's Mid-Continent/Gulf States region includes the following significant operating areas:

- South Texas - Includes non-operated positions in approximately 1,000 net acres in the Flores field. This area has significant NGL content associated with the natural gas.
- East Texas - Fidelity holds approximately 9,000 net acres, primarily natural gas and associated NGL.
- Other - Includes various non-operated onshore interests, as well as offshore interests in the shallow waters off the coasts of Texas and Louisiana.

Operating Information Annual net production by region for 2014 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	4,681	256	15,704	7,554	84%
Mid-Continent/Gulf States	238	353	5,118	1,444	16
Total	4,919	609	20,822	8,998	100%

Note: Bakken-Mountrail County represents 36% of total annual net oil production and is the only field that contains 15 percent or more of the Company's total proved reserves as of December 31, 2014.

Annual net production by region for 2013 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	4,481	250	19,461	7,975	78%
Mid-Continent/Gulf States	334	531	8,547	2,289	22
Total	4,815	781	28,008	10,264	100%

Note: Bakken-Mountrail County represents 43% of total annual net oil production and is the only field that contains 15 percent or more of the Company's total proved reserves as of December 31, 2013.

Annual net production by region for 2012 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	3,295	249	23,180	7,408	74%
Mid-Continent/Gulf States	399	579	10,034	2,650	26
Total	3,694	828	33,214	10,058	100%

Note: Bakken-Mountrail County represents 47% of total annual net oil production and is the only field that contains 15 percent or more of the Company's total proved reserves as of December 31, 2012.

Well and Acreage Information Gross and net productive well counts and gross and net developed and undeveloped acreage related to Fidelity's interests at December 31, 2014 , were as follows:

	Gross *	Net **
Productive wells:		
Oil	924	195
Natural gas	2,075	1,580
Total	2,999	1,775
Developed acreage (000's)	527	328
Undeveloped acreage set to expire in the years (000's):		
2015	141	80
2016	23	12
2017	5	5
Thereafter	569	276
Total undeveloped acreage	738	373

* Reflects well or acreage in which an interest is owned.
** Reflects Fidelity's percentage of ownership.

In most cases, acreage set to expire can be held through drilling operations or the Company can exercise extension options.

Delivery Commitments At December 31, 2014 , Fidelity has commitments to deliver fixed and determinable amounts of oil under contract for all of its Mountrail County production for the first quarter of 2015. Fidelity does not have any material delivery commitments to deliver fixed and determinable amounts of natural gas at December 31, 2014 .

Exploratory and Development Wells The following table reflects activities related to Fidelity's oil and natural gas wells drilled and/or tested during 2014 , 2013 and 2012 :

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2014	**—**	**1**	**1**	**20**	**1**	**21**	**22**
2013	3	2	5	35	3	38	43
2012	24	3	27	39	1	40	67

At December 31, 2014 , there were 28 gross (8 net) wells in the process of drilling or under evaluation, all of which were development wells. These wells are not included in the previous table. Fidelity expects to complete the drilling and testing of these wells within the next 12 months.

The information in the preceding table should not be considered indicative of future performance nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons whether or not they produce a reasonable rate of return.

Competition The exploration and production industry is highly competitive. Fidelity competes with a substantial number of major and independent exploration and production companies in securing the equipment, services and expertise necessary to develop and operate its properties.

Environmental Matters Fidelity's operations are generally subject to federal, state and local environmental and operational laws and regulations. Fidelity believes it is in substantial compliance with these regulations.

The ongoing operations of Fidelity are subject to the Clean Air Act, the Clean Water Act, the NEPA, ESA and other state, federal and local regulations. Administration of many provisions of these laws has been delegated to the states where Fidelity operates. 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 under federal and state laws are required as part of the permitting process covering the conduct of drilling and production operations as well as in the abandonment and reclamation of facilities.

In connection with production operations, Fidelity has not incurred any material capital environmental expenditures in 2014 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2017 .

Proved Reserve Information Estimates of proved oil, NGL and natural gas 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. Other factors used in the proved reserve estimates are prices, market differentials, estimates of well operating and future development 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 proved 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. The technical person responsible for overseeing the preparation of the reserve estimates holds a bachelor of science degree in mathematics with a technical minor in petroleum engineering, has 27 years of experience in petroleum engineering and reserve estimation, and is a member of the Society of Petroleum Engineers. In addition, the Company engages an independent third party to audit its proved reserves. Ryder Scott reviewed the Company's proved reserve quantity estimates as of December 31, 2014 . The technical person at Ryder Scott primarily responsible for overseeing the reserves audit is a Senior Vice President with over 30 years of experience in estimating and auditing reserves attributable to oil and gas properties, holds a bachelor of science degree in mechanical engineering, is a registered professional engineer, and is a member of multiple professional organizations.

Fidelity's proved reserves by region at December 31, 2014 , are as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total	PV-10 Value (in millions) *
Rocky Mountain	42,018	2,865	160,866	71,694	78%	$ 1,288.5
Mid-Continent/Gulf States	1,900	4,322	84,145	20,246	22	140.8
Total proved reserves	43,918	7,187	245,011	91,940	100%	1,429.3
Discounted future income taxes						354.4
Standardized measure of discounted future net cash flows relating to proved reserves						$ 1,074.9

* Pre-tax PV-10 value is a non-GAAP financial measure that is derived from the most directly comparable GAAP financial measure which is the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows disclosed in Item 8 - Supplementary Financial Information, is presented after deducting discounted future income taxes, whereas the PV-10 value is presented before income taxes. Pre-tax PV-10 value is commonly used by the Company to evaluate properties that are acquired and sold and to assess the potential return on investment in the Company's oil and natural gas properties. The Company believes pre-tax PV-10 value is a useful supplemental disclosure to the standardized measure as the Company believes readers may utilize this value as a basis for comparison of the relative size and value of the Company's reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. However, pre-tax PV-10 value is not a substitute for the standardized measure of discounted future net cash flows. Neither the pre-tax PV-10 value nor the standardized measure of discounted future net cash flows purports to represent the fair value of the Company's oil and natural gas properties.

For more information related to oil and natural gas interests, see Item 8 - Note 1 and Supplementary Financial Information.

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 19.

The construction materials business had approximately $438 million in backlog at December 31, 2014 , compared to $456 million at December 31, 2013 . The Company anticipates that a significant amount of the current backlog will be completed during 2015 .

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 1.0 billion tons of the 1.1 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 were calculated by dividing remaining reserves by the three-year average sales from 2012 through 2014 . 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, 2014 , and sales for the years ended December 31, 2014 , 2013 and 2012 :

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)					
Production Area	owned	leased	owned	leased	**2014**	2013	2012	Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Anchorage, AK	—	—	1	—	**1,665**	1,074	110	19,153	N/A	20
Hawaii	—	6	—	—	**1,840**	1,672	1,678	55,493	2017-2064	32
Northern CA	—	—	9	1	**1,340**	1,525	1,203	53,784	2018	40
Southern CA	—	2	—	—	**147**	241	784	91,963	2035	Over 100
Portland, OR	1	3	5	3	**3,244**	3,343	2,698	228,710	2025-2055	74
Eugene, OR	3	4	4	1	**928**	825	847	167,464	2016-2046	Over 100
Central OR/WA/ID	1	1	5	4	**1,254**	1,045	1,131	115,361	2020-2077	Over 100
Southwest OR	5	4	11	6	**1,624**	1,465	1,613	95,586	2017-2053	61
Central MT	—	—	1	2	**1,260**	1,236	1,200	27,173	2023-2027	22
Northwest MT	—	—	7	2	**1,486**	1,242	1,011	64,538	2016-2020	52
Wyoming	—	—	1	1	**952**	983	428	10,619	2019	13
Central MN	—	1	36	20	**1,674**	1,578	1,714	64,058	2015-2028	39
Northern MN	2	—	18	5	**491**	349	195	26,896	2015-2017	78
ND/SD	—	—	7	14	**2,377**	1,862	1,711	29,099	2015-2031	15
Texas	1	—	1	—	**903**	672	692	11,259	2022	15
Sales from other sources					**4,642**	5,601	6,270			
					25,827	24,713	23,285	1,061,156		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2014 , are comprised of 497 million tons that are owned and 564 million tons that are leased. Approximately 48 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 24 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2012 through 2014 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 69 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 are as follows:

	2014	2013	2012
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,083,376**	1,088,236	1,088,833
Acquisitions	**12,343**	22,682	950
Sales volumes*	**(21,185)**	(19,112)	(17,320)
Other**	**(13,378)**	(8,430)	15,773
End of year	**1,061,156**	1,083,376	1,088,236

* Excludes sales from other sources.
** Includes property sales and revisions of previous estimates.

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 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 that 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 2014 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 2017 .

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 19 .

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

Construction Services

General MDU Construction Services specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment. These services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

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, 2014 , 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, 2014 , was approximately $305 million compared to $459 million at December 31, 2013 . MDU Construction Services expects to complete a significant amount of this backlog during 2015 . 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 2014 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2017 .

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.

Economic Risks

The Company's exploration and production and pipeline and energy services businesses are dependent on factors, including commodity prices and commodity price basis differentials, that are subject to various external influences that cannot be controlled.

These factors include: fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; domestic and foreign supplies of oil, NGL and natural gas; political and economic conditions in oil producing countries; actions of the

Organization of Petroleum Exporting Countries; drilling successes in oil and natural gas operations; the timely receipt of necessary permits and approvals; the ability to retain employees to identify, drill for and develop reserves; utilizing appropriate technologies; irregularities in geological formations; and other risks incidental to the development and operations of oil and natural gas wells, processing plants and pipeline systems. Continued prolonged depressed prices for oil, NGL and natural gas could impede the growth of our pipeline and energy services business, and could negatively affect the results of operations, cash flows and asset values of the Company's exploration and production and pipeline and energy services businesses.

Actual quantities of recoverable oil, NGL and natural gas reserves and discounted future net cash flows from those reserves may vary significantly from estimated amounts. There is a risk that changes in estimates of proved reserve quantities or other factors including low oil and natural gas prices, could result in future noncash write-downs of the Company's oil and natural gas properties.

The process of estimating oil, NGL and natural gas reserves is complex. Reserve estimates are based on assumptions relating to oil, NGL and natural gas pricing, drilling and operating expenses, capital expenditures, taxes, timing of operations, and the percentage of interest owned by the Company in the properties. The proved reserve estimates are prepared for each of the Company's properties by internal engineers assigned to an asset team by geographic area. The internal engineers analyze available geological, geophysical, engineering and economic data for each geographic area. The internal engineers make various assumptions regarding this data. The extent, quality and reliability of this data can vary. Although the Company has prepared its proved reserve estimates in accordance with guidelines established by the industry and the SEC, significant changes to the proved reserve estimates may occur based on actual results of production, drilling, costs and pricing.

The Company bases the estimated discounted future net cash flows from proved reserves on prices and current costs in accordance with SEC requirements. Actual future prices and costs may be significantly different. Various factors, including lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in future noncash write-downs of the Company's oil and natural gas properties.

SEC Defined Prices for each quarter in 2014 were as follows:

SEC Defined Prices for the 12 months ended	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
December 31, 2014	$ 94.99	$ 4.34	$ 7.71
September 30, 2014	99.08	4.24	7.60
June 30, 2014	100.27	4.10	7.47
March 31, 2014	98.46	3.99	7.33

For purposes of comparison, first-of-the-month prices were as follows:

	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
January 2015	$ 53.27	$ 3.00	$ 3.06
February 2015	48.24	2.68	2.78

Given the current oil and natural gas pricing environment, the Company believes it is likely it will have noncash write-downs of its oil and natural gas properties in future quarters until such time as commodity prices begin to recover.

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

The construction, startup and operation of power generation facilities and Dakota Prairie Refinery involve many risks, which may include: delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to complete financing; inability to negotiate acceptable equipment acquisition, construction, fuel and crude oil supply, off-take, transmission, transportation or other material agreements; changes in markets and market prices for power, crude oil and refined products; cost increases and overruns; as well as the risk of performance below expected levels of output or efficiency. An additional risk for regulated projects would be 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.

Economic volatility 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 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 development and processing. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities and private individuals may interpret the Company's legal or regulatory requirements differently and seek injunctive relief or other remedies against the Company. The Company cannot predict the outcome (financial or operational) of any such litigation or administrative proceedings.

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

In December 2011, the EPA finalized the Mercury and Air Toxics Standards rules that will require reductions in mercury and other air emissions from coal- and oil-fired electric utility steam generating units. Montana-Dakota evaluated the pollution control technologies needed at its electric generation resources to comply with this rule and determined that the Lewis & Clark Station near Sidney, Montana, will require additional particulate matter control for non-mercury metal emissions. Montana-Dakota has further evaluated pollution control options and intends to comply with the rule by making scrubber modifications, including installation of a mist eliminator and sieve tray. Controls must be in place by April 16, 2015, or April 16, 2016, if a one-year extension is granted for completion of the pollution control project. Because a one-year extension is needed to install the pollution control project, Montana-Dakota submitted a timely request for approval of a one-year compliance extension to the Montana DEQ on November 24, 2014. On January 30, 2015, the Montana DEQ approved the one-year extension.

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 requirements or have completed studies that project compliance expenditures are not material. The Lewis & Clark Station will complete a study by 2018 that will be used to determine any required controls. It is unknown at this time what controls are 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.

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

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

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

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. On June 25, 2013, President Obama released his Climate Action Plan for the U.S. in which he stated his goal to reduce GHG emissions "in the range of 17 percent" below 2005 levels by 2020. The president issued a memorandum to the EPA on the same day, instructing the EPA to re-propose the GHG NSPS rule for new electric generation units. The EPA released the re-proposed rule on January 8, 2014, in the Federal Register, which takes the place of the rule proposed in 2012 for new electric generation units that the EPA did not finalize. This rule applies to new fossil fuel-fired electric generation units, including coal-fired units, natural gas-fired combined-cycle units and natural gas-fired simple-cycle peaking units. The EPA's 1,100 pounds of carbon dioxide per MW hour emissions standard for coal-fired units does not allow any new coal-fired electric generation to be constructed unless carbon dioxide is captured and sequestered.

President Obama also directed the EPA to develop a GHG NSPS standard for existing fossil fuel-fired electric generation units by June 1, 2014, with finalization by June 1, 2015. On June 18, 2014, the EPA published in the Federal Register a proposed rule limiting carbon dioxide emissions from existing fossil fuel-fired electric generating units and a separate proposed rule limiting carbon dioxide emissions from existing units that are modified or reconstructed.

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

The Company’s primary GHG emission is carbon dioxide from fossil fuels combustion at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 60 percent of Montana-Dakota's owned generating capacity and more than 90 percent of the electricity it generates is from coal-fired facilities.

There may also be new treaties, legislation or regulations to reduce GHG emissions that could affect Montana-Dakota's electric utility operations by requiring additional energy conservation efforts or renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs. If Montana-Dakota does not receive timely and full recovery of GHG emission compliance costs from its customers, then such costs could adversely impact the results of its operations.

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

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

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.

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, industry rate structures, health care legislation, tax legislation 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. 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 and drilling activities for the pipeline and energy services and exploration and production businesses. In addition, severe weather can be destructive, causing outages, reduced oil and natural gas production, 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 is increasing in all of the Company's businesses.

All of the Company's businesses are subject to increased 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, volatility in natural gas prices and other factors. The pipeline and energy services business competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. The exploration and production business is subject to competition in the acquisition and development of oil and natural gas properties. The increase in 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.

An increase in costs related to obligations under MEPPs could have a material negative effect on the Company's results of operations and cash flows.

Various operating subsidiaries of the Company participate in approximately 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 $14 million (approximately $8.4 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, viruses, acts of terrorism 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 production, storage and pipeline systems, may be unable to fulfill critical business functions, including a loss of service to customers. Any such disruption could result in a decrease in the Company's 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, a disruption elsewhere in the system could negatively impact the Company's business.

The Company's business requires access to sensitive customer, employee 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 plans to market and sell its exploration and production business, there is no assurance that it will be successful.

As part of the Company’s corporate strategy, it plans to market and sell its exploration and production assets and exit that line of business. The Company has delayed its plan to market Fidelity in light of the recent volatility of oil prices. At such time as the marketing resumes, such a disposition and exit will be subject to various risks, including: suitable purchasers may not be available or willing to purchase the assets on terms and conditions acceptable to the Company or may only be interested in acquiring a portion of the assets; the agreements pursuant to which the Company divests the assets may contain continuing indemnification obligations; the inability to obtain waivers from applicable covenants under debt agreements; the Company may incur substantial costs in connection with the marketing and sale of the assets; the marketing and sale of the assets could distract management, divert resources, disrupt the Company’s ongoing business and make it difficult for the Company to maintain its current business standards, controls and procedures; uncertainties associated with the sale may cause a loss of key management personnel at Fidelity which could make it more difficult to sell the assets or operate the business in the event that the Company is unable to sell it; sale of the assets could result in substantial tax liability; the Company may be required to record an impairment charge that could have an adverse effect on the Company’s financial condition; and the Company may not be able to redeploy the proceeds from any sale of the assets in a manner that produces similar revenues and growth rates or enhances shareholder value.

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 the various 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 19 , 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.

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 2014 and 2013 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
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
2013			
First quarter	$25.00	$21.50	$.1725
Second quarter	27.14	23.37	.1725
Third quarter	30.21	25.94	.1725
Fourth quarter	30.97	27.53	.1775
			$.6950

As of December 31, 2014 , the Company's common stock was held by approximately 13,300 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 12 .

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, 2014	—			
November 1 through November 30, 2014	40,506	$25.34		
December 1 through December 31, 2014	2,582	23.56		
Total	43,088			

(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.

Item 6. Selected Financial Data

	2014	2013	2012 (a)	2011	2010	2009 (b)
Selected Financial Data						
Operating revenues (000's):						
Electric	**$ 277,874**	$ 257,260	$ 236,895	$ 225,468	$ 211,544	$ 196,171
Natural gas distribution	**921,986**	851,945	754,848	907,400	892,708	1,072,776
Pipeline and energy services	**215,868**	202,068	193,157	278,343	329,809	307,827
Exploration and production	**547,571**	536,023	448,617	453,586	434,354	439,655
Construction materials and contracting	**1,765,330**	1,712,137	1,617,425	1,510,010	1,445,148	1,515,122
Construction services	**1,119,529**	1,039,839	938,558	854,389	789,100	819,064
Other	**9,364**	9,620	10,370	11,446	7,727	9,487
Intersegment eliminations	**(186,964)**	(146,488)	(124,439)	(190,150)	(200,695)	(183,601)
	$ 4,670,558	$ 4,462,404	$ 4,075,431	$ 4,050,492	$ 3,909,695	$ 4,176,501
Operating income (loss) (000's):						
Electric	**$ 61,331**	$ 54,274	$ 49,852	$ 49,096	$ 48,296	$ 36,709
Natural gas distribution	**65,633**	78,829	67,579	82,856	75,697	76,899
Pipeline and energy services	**37,616**	20,046	49,139	45,365	46,310	69,388
Exploration and production	**158,229**	161,402	(276,642)	133,790	143,169	(473,399)
Construction materials and contracting	**86,462**	93,629	57,864	51,092	63,045	93,270
Construction services	**82,309**	85,246	66,531	39,144	33,352	44,255
Other	**5,734**	6,649	4,884	5,024	858	(219)
Intersegment eliminations	**(9,089)**	(7,176)	—	—	—	—
	$ 488,225	$ 492,899	$ 19,207	$ 406,367	$ 410,727	$ (153,097)
Earnings (loss) on common stock (000's):						
Electric	**$ 36,731**	$ 34,837	$ 30,634	$ 29,258	$ 28,908	$ 24,099
Natural gas distribution	**30,484**	37,656	29,409	38,398	36,944	30,796
Pipeline and energy services	**22,628**	7,629	26,588	23,082	23,208	37,845
Exploration and production	**96,733**	94,450	(177,283)	80,282	85,638	(296,730)
Construction materials and contracting	**51,510**	50,946	32,420	26,430	29,609	47,085
Construction services	**54,432**	52,213	38,429	21,627	17,982	25,589
Other	**7,461**	5,136	4,797	6,190	21,046	7,357
Intersegment eliminations	**(5,608)**	(4,307)	—	—	—	—
Earnings (loss) on common stock before income (loss) from discontinued operations	**294,371**	278,560	(15,006)	225,267	243,335	(123,959)
Income (loss) from discontinued operations, net of tax	**3,177**	(312)	13,567	(12,926)	(3,361)	—
	$ 297,548	$ 278,248	$ (1,439)	$ 212,341	$ 239,974	$ (123,959)
Earnings (loss) per common share before discontinued operations - diluted	**$ 1.53**	$ 1.47	$ (.08)	$ 1.19	$ 1.29	$ (.67)
Discontinued operations, net of tax	**.02**	—	.07	(.07)	(.02)	—
	$ 1.55	$ 1.47	$ (.01)	$ 1.12	$ 1.27	$ (.67)
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	**192,587**	189,693	188,826	188,905	188,229	185,175
Dividends declared per common share	**$ .7150**	$ .6950	$ .6750	$ .6550	$ .6350	$ .6225
Book value per common share	**$ 16.66**	$ 15.01	$ 13.95	$ 14.62	$ 14.22	$ 13.61
Market price per common share (year end)	**$ 23.50**	$ 30.55	$ 21.24	$ 21.46	$ 20.27	$ 23.60
Market price ratios:						
Dividend payout	**46%**	47%	(c)	58%	50%	(c)
Yield	**3.1%**	2.3%	3.2%	3.1%	3.2%	2.7%
Market value as a percent of book value	**141.1%**	203.5%	152.3%	146.8%	142.5%	173.4%

(a) Reflects $246.8 million of after-tax noncash write-downs of oil and natural gas properties.
(b) Reflects a $384.4 million after-tax noncash write-down of oil and natural gas properties.
(c) Not meaningful due to effects of the after-tax noncash write-down(s), as previously discussed.

Item 6. Selected Financial Data (continued)

	2014	2013	2012	2011	2010	2009
General						
Total assets (000's)	**$ 7,809,978**	$ 7,061,332	$ 6,682,491	$ 6,556,125	$ 6,303,549	$ 5,990,952
Total long-term debt (000's)	**$ 2,094,727**	$ 1,854,563	$ 1,744,975	$ 1,424,678	$ 1,506,752	$ 1,499,306
Capitalization ratios:						
Common equity	**61%**	60%	60%	66%	64%	63%
Total debt	**39**	40	40	34	36	37
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**3,308,358**	3,173,086	2,996,528	2,878,852	2,785,710	2,663,560
Electric system summer and firm purchase contract ZRCs (Interconnected system)	**584.0**	583.5	552.8	572.8	553.3	(a)
Electric system peak demand obligation, including firm purchase contracts, ZRCs (Interconnected system)	**522.4**	508.3	550.7	524.2	529.5	(a)
Demand peak - kW (Interconnected system)	**582,083**	573,587	573,587	535,761	525,643	525,643
Electricity produced (thousand kWh)	**2,519,938**	2,430,001	2,299,686	2,488,337	2,472,288	2,203,665
Electricity purchased (thousand kWh)	**1,010,422**	971,261	870,516	645,567	521,156	682,152
Average cost of fuel and purchased power per kWh	**$ .025**	$ .025	$ .023	$ .021	$ .021	$ .023
Natural Gas Distribution						
Sales (Mdk)	**104,297**	108,260	93,810	103,237	95,480	102,670
Transportation (Mdk)	**145,941**	149,490	132,010	124,227	135,823	132,689
Degree days (% of normal)						
Montana-Dakota/Great Plains	**103%**	105%	84%	101%	98%	104%
Cascade	**89%**	98%	96%	103%	96%	105%
Intermountain	**95%**	110%	91%	107%	100%	107%
Pipeline and Energy Services						
Transportation (Mdk)	**233,483**	178,598	137,720	113,217	140,528	163,283
Gathering (Mdk)	**38,372**	40,737	47,084	66,500	77,154	92,598
Customer natural gas storage balance (Mdk)	**14,885**	26,693	43,731	36,021	58,784	61,506
Exploration and Production						
Production:						
Oil (MBbls)	**4,919**	4,815	3,694	2,724	2,767	2,557
NGL (MBbls)	**609**	781	828	776	495	554
Natural gas (MMcf)	**20,822**	28,008	33,214	45,598	50,391	56,632
Total production (MBOE)	**8,998**	10,264	10,058	11,099	11,661	12,550
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):						
Oil (per Bbl)	**$ 83.33**	$ 89.70	$ 84.84	$ 91.62	$ 70.61	$ 53.57
NGL (per Bbl)	**$ 36.06**	$ 37.39	$ 39.81	$ 54.06	$ 44.93	$ 32.18
Natural gas (per Mcf)	**$ 4.02**	$ 2.89	$ 2.08	$ 3.30	$ 3.57	$ 2.99
Average realized prices (including realized gain/loss on commodity derivatives):						
Oil (per Bbl)	**$ 85.96**	$ 89.35	$ 86.54	$ 86.20	$ 69.59	$ 50.67
NGL (per Bbl)	**$ 36.06**	$ 37.39	$ 39.81	$ 54.06	$ 44.93	$ 32.18
Natural gas (per Mcf)	**$ 3.81**	$ 2.96	$ 2.91	$ 3.84	$ 4.36	$ 5.16
Proved reserves:						
Oil (MBbls)	**43,918**	41,019	33,453	27,005	25,666	25,930
NGL (MBbls)	**7,187**	6,602	7,153	7,342	7,201	8,286
Natural gas (MMcf)	**245,011**	198,445	239,278	379,827	448,397	448,425
Total proved reserves (MBOE)	**91,940**	80,695	80,486	97,651	107,599	108,954
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**25,827**	24,713	23,285	24,736	23,349	23,995
Asphalt (tons)	**6,070**	6,228	5,988	6,709	6,279	6,360
Ready-mixed concrete (cubic yards)	**3,460**	3,223	3,157	2,864	2,764	3,042
Aggregate reserves (000's tons)	**1,061,156**	1,083,376	1,088,236	1,088,833	1,107,396	1,125,491

(a) Information not available for periods prior to 2010.

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 business segments, see Item 8 - Note 15 .

Key Strategies and Challenges

Electric and Natural Gas Distribution

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

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

Pipeline and Energy Services

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

Challenges Challenges for this segment include: energy price volatility; tight natural gas basis differentials; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other pipeline and energy services companies.

Exploration and Production

Strategy The Company intends to market and sell its exploration and production business. However, the Company has delayed its plan in light of the recent volatility in oil prices. Until such sale is accomplished, this segment will apply technology and utilize existing expertise to increase production and reserves from existing leaseholds. By optimizing existing operations, this segment is focused on balancing its oil and natural gas commodity mix to maximize profitability.

Challenges Risks and uncertainties associated with the marketing and sale of the Fidelity assets; current oil and natural gas low-price environment; timely receipt of necessary permits and approvals; environmental and regulatory requirements; recruitment and retention of a skilled workforce; utilizing appropriate technologies; inflationary pressure on development and operating costs; irregularities in geological formations; and competition from other exploration and production companies are ongoing challenges for this segment.

Construction Materials and Contracting
Strategy Focus on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; develop and recruit talented employees; and continue growth through organic and acquisition opportunities. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, asphalt concrete, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Recruitment and retention of key personnel and volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel, continue to be a concern. This business unit expects to continue cost containment efforts, positioning its operations for the resurgence in the private market, while continuing the emphasis on industrial, energy and public works projects.

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

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls, retention of key personnel, managing through downturns in the economy and effective management of working capital are ongoing challenges.

For more information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see Item 1A - Risk Factors. 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,	**2014**	2013	2012
	(Dollars in millions, where applicable)		
Electric	**$ 36.7**	$ 34.8	$ 30.6
Natural gas distribution	**30.5**	37.7	29.4
Pipeline and energy services	**22.6**	7.6	26.6
Exploration and production	**96.8**	94.5	(177.2)
Construction materials and contracting	**51.5**	50.9	32.4
Construction services	**54.5**	52.2	38.4
Other	**7.5**	5.1	4.8
Intersegment eliminations	**(5.7)**	(4.3)	—
Earnings (loss) before discontinued operations	**294.4**	278.5	(15.0)
Income (loss) from discontinued operations, net of tax	**3.1**	(.3)	13.6
Earnings (loss) on common stock	**$ 297.5**	$ 278.2	$ (1.4)
Earnings (loss) per common share - basic:			
Earnings (loss) before discontinued operations	**$ 1.53**	$ 1.47	$ (.08)
Discontinued operations, net of tax	**.02**	—	.07
Earnings (loss) per common share - basic	**$ 1.55**	$ 1.47	$ (.01)
Earnings (loss) per common share - diluted:			
Earnings (loss) before discontinued operations	**$ 1.53**	$ 1.47	$ (.08)
Discontinued operations, net of tax	**.02**	—	.07
Earnings (loss) per common share - diluted	**$ 1.55**	$ 1.47	$ (.01)

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
- Other earnings and earnings from discontinued operations 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.

2013 compared to 2012 Consolidated earnings for 2013 increased $279.6 million from the prior year. This increase was due to:

- Absence of the write-downs of oil and natural gas properties of $246.8 million (after tax), as discussed in Item 8 - Note 1 , increased oil production and higher average realized natural gas and oil prices, partially offset by a lower realized gain on commodity derivatives of $21.1 million (after tax), higher depreciation, depletion and amortization expense, decreased natural gas production, higher production taxes, as well as higher general and administrative expense at the exploration and production business
- Higher asphalt and aggregate margins and volumes at the construction materials and contracting business
- Higher workloads and margins in the Western and Central regions, as well as higher equipment sales and rental revenue and margins at the construction services business
- Increased retail sales volumes and a $2.8 million (after tax) gain on the sale of a nonregulated appliance service and repair business, partially offset by higher operation and maintenance expense, as well as higher depreciation, depletion and amortization expense at the natural gas distribution business

Partially offsetting these increases were:

- A net benefit in 2013 of $1.5 million (after tax) compared to $15.0 million (after tax) in 2012, related to the natural gas gathering operations litigation, as discussed in Item 8 - Note 19 , as well as an impairment of coalbed natural gas gathering assets of $9.0 million (after tax) in 2013 compared to an impairment of $1.7 million (after tax) in 2012, as discussed in Item 8 - Note 1 , at the pipeline and energy services business
- Loss from discontinued operations of $300,000 (after tax) in 2013, compared to income from discontinued operations of $13.6 million (after tax) in 2012, primarily due to the absence in 2013 of a net benefit in 2012 related to the reversal of an arbitration charge resulting from a favorable court ruling, as discussed in Item 8 - Note 3

Financial and Operating Data

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

Electric

Years ended December 31,	**2014**	2013	2012
	(Dollars in millions, where applicable)		
Operating revenues	**$ 277.9**	$ 257.3	$ 236.9
Operating expenses:			
Fuel and purchased power	**89.3**	83.5	72.4
Operation and maintenance	**81.1**	76.5	71.8
Depreciation, depletion and amortization	**35.0**	32.8	32.5
Taxes, other than income	**11.1**	10.2	10.3
	216.5	203.0	187.0
Operating income	**61.4**	54.3	49.9
Earnings	**$ 36.7**	$ 34.8	$ 30.6
Retail sales (million kWh)	**3,308.4**	3,173.1	2,996.5
Average cost of fuel and purchased power per kWh	**$ .025**	$ .025	$ .023

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

2013 compared to 2012 Electric earnings increased $4.2 million (14 percent) compared to the prior year due to:

- Higher electric retail sales margins, including the result of 6 percent higher volumes, primarily to residential, commercial and industrial customers due to increased residential customer growth and weather variances from last year
- Higher other income, largely higher allowance for funds used during construction of $800,000 (after tax)

These increases were partially offset by higher operation and maintenance expense, which includes $2.3 million (after tax) largely related to higher payroll-related costs and increased contract services, offset in part by lower benefit-related costs.

Natural Gas Distribution

Years ended December 31,	2014	2013	2012
	(Dollars in millions, where applicable)		
Operating revenues	**$ 922.0**	$ 851.9	$ 754.8
Operating expenses:			
Purchased natural gas sold	**603.2**	534.8	457.4
Operation and maintenance	**150.2**	142.3	139.4
Depreciation, depletion and amortization	**54.7**	50.0	45.7
Taxes, other than income	**48.3**	46.0	44.7
	856.4	773.1	687.2
Operating income	**65.6**	78.8	67.6
Earnings	**$ 30.5**	$ 37.7	$ 29.4
Volumes (MMdk):			
Sales	**104.3**	108.3	93.8
Transportation	**145.9**	149.5	132.0
Total throughput	**250.2**	257.8	225.8
Degree days (% of normal)*			
Montana-Dakota/Great Plains	**103%**	105%	84%
Cascade	**89%**	98%	96%
Intermountain	**95%**	110%	91%
Average cost of natural gas, including transportation, per dk	**$ 5.78**	$ 4.94	$ 4.88

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

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

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

2013 compared to 2012 The natural gas distribution business experienced an increase in earnings of $8.3 million (28 percent) compared to the prior year due to:

- Increased retail sales volumes of 15 percent, largely resulting from increased customer growth and colder weather than last year, partially offset by weather normalization adjustments in certain jurisdictions
- A $2.8 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business
- Lower net interest expense, which includes $2.3 million (after tax) largely related to lower average interest rates

These increases were partially offset by:

- Higher operation and maintenance expense, which includes $3.4 million (after tax) largely related to higher payroll-related costs, offset in part by lower benefit-related costs
- Increased depreciation, depletion and amortization expense of $2.7 million (after tax), primarily resulting from higher property, plant and equipment balances
- Lower other income, which includes $2.0 million (after tax) largely related to lower allowance for funds used during construction

Pipeline and Energy Services

Years ended December 31,	**2014**	2013	2012
		(Dollars in millions)	
Operating revenues	**$ 215.9**	$ 202.1	$ 193.1
Operating expenses:			
Purchased natural gas sold	**58.8**	57.5	50.5
Operation and maintenance*	**75.4**	81.8	52.2
Depreciation, depletion and amortization	**30.7**	29.1	27.7
Taxes, other than income	**13.4**	13.6	13.6
	178.3	182.0	144.0
Operating income	**37.6**	20.1	49.1
Earnings*	**$ 22.6**	$ 7.6	$ 26.6
Transportation volumes (MMdk)	**233.5**	178.6	137.7
Natural gas gathering volumes (MMdk)	**38.4**	40.7	47.1
Customer natural gas storage balance (MMdk):			
Beginning of period	**26.7**	43.7	36.0
Net injection (withdrawal)	**(11.8)**	(17.0)	7.7
End of period	**14.9**	26.7	43.7

* Reflects an impairment of coalbed natural gas gathering assets of $14.5 million ($9.0 million after tax) in second quarter 2013 and $2.7 million ($1.7 million after tax) in second quarter 2012, as well as a net benefit of $2.5 million ($1.5 million after tax) in fourth quarter 2013 and $24.1 million ($15.0 million after tax) in second quarter 2012 related to the natural gas gathering operations litigation, largely reflected in operation and maintenance expense, as discussed in Item 8 - Note 19 .

2014 compared to 2013 Pipeline and energy services earnings increased $15.0 million (197 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 $1.8 million of higher income tax benefits

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
- Higher operation and maintenance expense (excluding the asset impairment, net benefit related to natural gas gathering operations litigation and Pronghorn-related expense), which includes $1.6 million (after tax) largely payroll and benefits-related due to start-up costs related to Dakota Prairie Refinery
- 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 19

2013 compared to 2012 Pipeline and energy services earnings decreased $19.0 million (71 percent) largely due to:

- A net benefit in 2013 of $1.5 million (after tax) compared to $15.0 million (after tax) in 2012, related to the natural gas gathering operations litigation, as discussed in Item 8 - Note 19
- An impairment of coalbed natural gas gathering assets of $9.0 million (after tax) in 2013, compared to an impairment of $1.7 million (after tax) in 2012, largely resulting from lower natural gas prices, as discussed in Item 8 - Note 1
- Lower storage services revenue of $3.1 million (after tax), primarily due to lower average rates and lower storage balances
- Lower earnings of $3.1 million (after tax) resulting from lower natural gas gathering volumes from existing operations, largely resulting from customers experiencing production curtailments, normal declines and deferral of natural gas development activity

Partially offsetting the earnings decrease were:

- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, which were acquired in May 2012, primarily due to higher volumes
- Lower operation and maintenance expense (excluding the asset impairments, net benefits related to the natural gas gathering operations litigation and Pronghorn-related expense), which includes $2.0 million (after tax), largely related to lower payroll-related costs, legal and contract services
- Lower depreciation, depletion and amortization expense (excluding depreciation on Pronghorn oil and natural gas gathering and processing assets), which includes $1.6 million (after tax), primarily related to the coalbed areas

Exploration and Production

Years ended December 31,	2014	2013	2012
	(Dollars in millions, where applicable)		
Operating revenues:			
Oil	**$ 409.9**	$ 431.9	$ 313.4
NGL	**22.0**	29.2	33.0
Natural gas	**83.8**	81.0	69.2
Realized gain on commodity derivatives	**8.5**	.2	33.6
Unrealized gain (loss) on commodity derivatives	**23.4**	(6.3)	(.6)
	547.6	536.0	448.6
Operating expenses:			
Operation and maintenance:			
Lease operating costs	**88.2**	82.2	77.7
Gathering and transportation	**12.5**	15.4	17.4
Other	**43.3**	42.9	37.0
Depreciation, depletion and amortization	**198.1**	186.4	160.7
Taxes, other than income:			
Production and property taxes	**46.1**	46.6	39.7
Other	**1.1**	1.1	1.0
Write-downs of oil and natural gas properties	**—**	—	391.8
	389.3	374.6	725.3
Operating income (loss)	**158.3**	161.4	(276.7)
Earnings (loss)	**$ 96.8**	$ 94.5	$ (177.2)
Production:			
Oil (MBbls)	**4,919**	4,815	3,694
NGL (MBbls)	**609**	781	828
Natural gas (MMcf)	**20,822**	28,008	33,214
Total production (MBOE)	**8,998**	10,264	10,058
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):			
Oil (per Bbl)	**$ 83.33**	$ 89.70	$ 84.84
NGL (per Bbl)	**$ 36.06**	$ 37.39	$ 39.81
Natural gas (per Mcf)	**$ 4.02**	$ 2.89	$ 2.08
Average realized prices (including realized gain/loss on commodity derivatives):			
Oil (per Bbl)	**$ 85.96**	$ 89.35	$ 86.54
NGL (per Bbl)	**$ 36.06**	$ 37.39	$ 39.81
Natural gas (per Mcf)	**$ 3.81**	$ 2.96	$ 2.91
Average depreciation, depletion and amortization rate, per BOE	**$ 21.17**	$ 17.41	$ 15.28
Production costs, including taxes, per BOE:			
Lease operating costs	**$ 9.80**	$ 8.01	$ 7.73
Gathering and transportation	**1.38**	1.50	1.73
Production and property taxes	**5.12**	4.54	3.94
	$ 16.30	$ 14.05	$ 13.40

2014 compared to 2013 Earnings at the exploration and production business increased $2.3 million (2 percent) 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 $7.4 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

2013 compared to 2012 Earnings at the exploration and production business increased $271.7 million due to:

- Absence of the write-downs of oil and natural gas properties of $246.8 million (after tax), as discussed in Item 8 - Note 1
- Increased oil production of 30 percent, primarily related to drilling activity in the Bakken and Paradox Basin areas
- Higher average realized natural gas prices of 39 percent, excluding gain/loss on commodity derivatives
- Higher average realized oil prices of 6 percent, excluding gain/loss on commodity derivatives

Partially offsetting these increases were:

- Lower realized gain on commodity derivatives of $21.1 million (after tax), due to higher commodity prices relative to hedge prices
- Higher depreciation, depletion and amortization expense of $16.2 million (after tax), largely due to higher depletion rates
- Decreased natural gas production of 16 percent, largely related to production curtailments, normal declines and deferral of certain natural gas development activity
- Higher production taxes of $4.3 million (after tax), primarily resulting from higher revenues
- Unrealized loss on commodity derivatives of $3.9 million (after tax) in 2013, compared to $400,000 (after tax) in 2012
- Higher general and administrative expense of $3.8 million (after tax), including higher payroll-related costs
- Higher net interest expense of $3.3 million (after tax), largely due to lower capitalized interest
- Increased lease operating expenses of $2.8 million (after tax), largely related to higher costs in the Bakken area resulting from increased production volumes and higher workover costs, as well as higher costs in the Paradox Basin resulting from increased production volumes, partially offset by lower costs at certain natural gas properties where curtailments of production have occurred

Construction Materials and Contracting

Years ended December 31,	2014	2013	2012
		(Dollars in millions)	
Operating revenues	**$ 1,765.3**	$ 1,712.1	$ 1,617.4
Operating expenses:			
Operation and maintenance*	**1,571.5**	1,505.2	1,442.5
Depreciation, depletion and amortization	**68.6**	74.5	79.5
Taxes, other than income	**38.8**	38.8	37.5
	1,678.9	1,618.5	1,559.5
Operating income	**86.4**	93.6	57.9
Earnings*	**$ 51.5**	$ 50.9	$ 32.4
Sales (000's):			
Aggregates (tons)	**25,827**	24,713	23,285
Asphalt (tons)	**6,070**	6,228	5,988
Ready-mixed concrete (cubic yards)	**3,460**	3,223	3,157

* Reflects a MEPP withdrawal liability of approximately $14 million ($8.4 million after tax). For more information, see Item 8 - Note 16 .

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 16
- Higher selling, general and administrative expense of $1.9 million (after tax), primarily due to higher payroll and benefit-related costs

2013 compared to 2012 Earnings at the construction materials and contracting business increased $18.5 million (57 percent) due to:

- Higher earnings of $6.6 million (after tax) resulting from higher asphalt margins and volumes
- Higher earnings of $5.6 million (after tax) resulting from higher aggregate margins and volumes
- Lower selling, general and administrative costs of $2.4 million (after tax), largely lower insurance costs
- Higher earnings of $1.4 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Increased construction workloads and margins of $1.4 million (after tax)
- Higher earnings resulting from higher other product line volumes and margins

Partially offsetting the increases was higher interest expense of $1.3 million (after tax), resulting from higher average interest rates.

Construction Services

Years ended December 31,	**2014**	2013	2012
		(In millions)	
Operating revenues	**$ 1,119.5**	$ 1,039.8	$ 938.6
Operating expenses:			
Operation and maintenance	**990.7**	910.7	831.9
Depreciation, depletion and amortization	**12.9**	11.9	11.1
Taxes, other than income	**33.6**	32.0	29.1
	1,037.2	954.6	872.1
Operating income	**82.3**	85.2	66.5
Earnings	**$ 54.5**	$ 52.2	$ 38.4

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; and 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.

2013 compared to 2012 Construction services earnings increased $13.8 million (36 percent) compared to the prior year primarily due to higher workloads and margins in the Western and Central regions, as well as higher equipment sales and rental revenue and margins. This increase was partially offset by higher general and administrative expense of $3.3 million (after tax), including higher payroll-related costs.

Other

Years ended December 31,	**2014**	2013	2012
		(In millions)	
Operating revenues	**$ 9.4**	$ 9.6	$ 10.4
Operating expenses:			
Operation and maintenance	**1.3**	.8	3.3
Depreciation, depletion and amortization	**2.2**	2.1	2.0
Taxes, other than income	**.2**	.1	.2
	3.7	3.0	5.5
Operating income	**5.7**	6.6	4.9
Income from continuing operations	**7.5**	5.1	4.8
Income (loss) from discontinued operations, net of tax	**3.1**	(.3)	13.6
Earnings	**$ 10.6**	$ 4.8	$ 18.4

2014 compared to 2013 Other earnings increased $5.8 million compared to the prior year primarily due to favorable income tax changes at both continuing and discontinued operations, including the resolution of certain tax matters and higher income tax benefits.

2013 compared to 2012 Other earnings decreased $13.6 million compared to the prior year primarily due to a loss from discontinued operations of $300,000 (after tax) in 2013, compared to income from discontinued operations of $13.6 million (after tax) in 2012, primarily due to the absence in 2013 of a net benefit in 2012 related to the reversal of an arbitration charge for a guarantee of a construction contract at the domestic power production business, which was sold in 2007, as discussed in Item 8 - Note 3 .

Intersegment Transactions

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

Years ended December 31,	**2014**	2013	2012
		(In millions)	
Intersegment transactions:			
Operating revenues	**$ 187.0**	$ 146.4	$ 124.4
Purchased natural gas sold	**92.0**	87.2	82.7
Operation and maintenance	**85.1**	52.1	41.7
Depreciation, depletion and amortization	**.8**	—	—
Earnings on common stock	**5.7**	4.3	—

For more information on intersegment eliminations, see Item 8 - Note 15 .

Prospective Information

The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for certain of the Company's businesses. Many of these highlighted points are "forward-looking statements." There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Item 1A - Risk Factors. 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's long-term compound annual growth goals on earnings per share from operations are in the range of 7 to 10 percent.
- The Company continually seeks opportunities to expand through organic growth opportunities and strategic acquisitions.
- The Company focuses on creating value through vertical integration between its business units.

Electric and natural gas distribution

- Rate base growth is projected to be approximately 11 percent compounded annually over the next five years, including plans for an approximate $1.8 billion gross capital investment program with $478 million planned for 2015. Although a prolonged period of lower commodity prices may slow Bakken-area growth in the future, the Company continues to see strong current growth.
- Regulatory actions
  - On July 10, 2014, the NDPSC approved recovery of $8.6 million annually effective July 15, 2014, to reflect actual costs incurred through February 2014 and projected costs through June 2015 for an environmental cost recovery rider related to costs resulting from the retrofit required to be installed at the Big Stone Station. The Company's share of the cost for the installation is approximately $90 million and is expected to be complete in 2015. The NDPSC had earlier approved advance determination of prudence for recovery of costs on the system.
  - On August 11, 2014, October 3, 2014 and February 6, 2015, the Company filed applications with the MTPSC, WYPSC and NDPSC, respectively, for natural gas rate increases, as discussed in Item 8 - Note 18 .
  - On November 14, 2014, the Company filed an application with the NDPSC for approval to implement the rate adjustment associated with the electric generation resource recovery rider, as discussed in Item 8 - Note 18 .
  - On December 22, 2014, the Company filed for advanced determination of prudence with the NDPSC on the Thunder Spirit Wind project, as discussed in Item 8 - Note 18 . The Company recently signed an agreement to purchase the project, which includes 43 wind turbines totaling 107.5 MW of electric generation at a cost of approximately $200 million with approximately $55 million already funded in 2014. The project is being developed by ALLETE Clean Energy with an expected completion in December 2015.

- The Company has a planned natural gas rate case filing in early 2015 for Oregon. The Company expects to file electric rate cases in 2015 in Montana and South Dakota and a natural gas case in Washington.

- Investments are being made in 2015 totaling approximately $60 million to serve the growing electric and natural gas customer base associated with the Bakken oil development where customer growth is higher than the national average. This reflects a slightly lower capital expenditure level compared to 2014 anticipating a tempering of economic activity due to recent lower oil prices.
- The Company is engaged in a 30-mile, approximately $60 million natural gas line project into the Hanford Nuclear Site in Washington.
- The Company, along with a partner, expects to build a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, about 160 miles. The Company's share of the cost is estimated at approximately $170 million. The project is a MISO multi-value project. A route application was filed in August 2013 with the state of South Dakota and in October 2013 with the state of North Dakota. A route permit was approved July 10, 2014, in North Dakota and August 13, 2014, in South Dakota. The South Dakota route permit was appealed and a district court ruled in favor of the project. The district court decision has been appealed to the South Dakota Supreme Court. The Company continues to expect the project to be complete in 2019.
- The Company is pursuing additional generation projects to meet projected capacity requirements, including 19 MW of natural gas generation at the Lewis & Clark Station slated for this year.
- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors, with company- and customer-owned pipeline facilities designed to serve existing facilities served by fuel oil or propane, and to serve new customers.
- The Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system in the Pacific Northwest and Idaho.

Pipeline and energy services

- The Company, in conjunction with Calumet formed Dakota Prairie Refining to develop, build and operate Dakota Prairie Refinery. Construction began on the facility in late March 2013 with a projected in-service date in the second quarter 2015. The Dakota Prairie Refinery will process Bakken crude into diesel, which will be marketed within the Bakken region. Other by-products, naphtha and atmospheric tower bottoms, are expected to be railed to other areas. The total project cost estimate is more than $400 million. EBITDA for the first full year of operation is projected to be in the range of $60 million to $80 million, to be shared equally with Calumet.
- The Company is evaluating the construction of a second 20,000-barrel-per-day topping plant to be located near Minot, North Dakota in the Bakken region. It is anticipated the economic evaluation of this project will continue through much of 2015.
- The Company continues work on acquiring right-of-way and easements as well as filing for applicable permits for its planned Wind Ridge Pipeline project, a 95-mile natural gas pipeline designed to deliver approximately 90 MMcf per day to an announced fertilizer plant near Spiritwood, North Dakota. The project cost is estimated to be approximately $120 million with an in-service date in 2017. There is an opportunity to expand this pipeline's capacity to serve other customers in eastern North Dakota.
- The Company has entered into 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. The Company will be holding an open season to gauge additional interest in the project. Project costs are estimated in the $50 million to $60 million range.
- The Company continues to pursue new growth opportunities and expansion of existing facilities and services offered to customers. The Company expects energy development to continue to grow long term within its geographic region, most notably in the Bakken area, where the Company owns an extensive natural gas pipeline system. The company plans to invest $1.1 billion of capital related to ongoing energy and industrial development over the next five years.

Exploration and production

- The Company intends to market its exploration and production company in the future and although an actual sale date is unknown, for forecasting purposes the Company is assuming a sale transaction after 2015.
- During 2015, the Company plans to continue to focus on maximizing the value of Fidelity to ultimately market it for sale including focusing on lowering its cost structure beyond the 25 percent general and administrative cost reduction already in place.
- The Company expects to spend approximately $111 million in gross capital expenditures in 2015 operating within projected cash flows. Plans are to minimize investments in the first half of the year to allow service costs to better align with the lower commodity price environment. The Company currently has no rigs drilling on its operated properties and anticipates commencing drilling in the second half of the year.
- Key activities for 2015 include:
  - Commissioning and start-up of the gas gathering and processing facilities in the Paradox in addition to new wells and existing well recompletes.
  - Completion of a backlog of wells in the non-operated Powder River Basin.
  - Drilling and completing additional horizontal wells in East Texas.

- ◦ Completion of 2014 activity carryover in the Bakken.
- Well updates:
  - ◦ The Cane Creek Unit 28-3 well (100 percent working interest) was completed in mid-December 2014 and was slowly ramped up to about 600 BOPD utilizing an 11/64ths-inch choke and a flowing tubing pressure of approximately 2,600 pounds per square inch. The production rate has been held relatively constant for the last three weeks.
  - ◦ The Company completed the Poovey Mark Poovey 1H well (100 percent working interest), its first East Texas Cotton Valley horizontal well. Initial production rate for the well peaked at 11 MMcf per day declining to recent rates of 9 MMcf per day.
- Annual oil production is expected to decline approximately 22 percent in 2015 primarily due to 2014 divestments in the Bakken and limited oil related investments in 2015. Annual natural gas and natural gas liquids volumes are estimated to decrease 10 percent and 20 percent respectively in 2015 primarily the result of 2014 asset divestments in South Texas. The December 2015 oil production rate is estimated to decrease 14 percent compared to December 2014, while natural gas and NGL rates are estimated to increase 4 percent and 23 percent, respectively. The Company is assuming average NYMEX index prices for 2015 of $50 per Bbl of crude oil, $3.00 per Mcf of natural gas and $24 per Bbl of NGL.
- Derivatives in place as of February 2, 2015, include:
  - ◦ For January through March 2015, 3,000 BOPD at a weighted average price of $98.00.
  - ◦ For January through March 2015, 15,000 MMBtu of natural gas per day at a weighted average price of $4.39.
  - ◦ For 2015, 10,000 MMBtu of natural gas per day at a weighted average price of $4.28.

Construction materials and contracting

- Approximate work backlog as of December 31, 2014, was $438 million, compared to $456 million a year ago. Private work represents 11 percent of construction backlog and public work represents 89 percent of backlog. The backlog includes a variety of projects such as highway grading, paving and underground projects, airports, bridge work and subdivisions.
- Projected revenues included in the Company's 2015 earnings guidance are in the range of $1.7 billion to $1.9 billion.
- The Company anticipates margins in 2015 to be in line with 2014 margins.
- 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 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

Construction services

- Approximate work backlog as of December 31, 2014, was $305 million, compared to $459 million a year ago. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including petrochemical work.
- Projected revenues included in the Company's 2015 earnings guidance are in the range of $1.1 billion to $1.3 billion.
- The Company anticipates margins in 2015 to be in line with 2014 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.

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 long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; oil, NGL and natural gas reserves; 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; the valuation of stock-based compensation; and the fair value of derivative instruments. 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 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 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, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

As these estimates change, calculated proved reserves may change. Changes in proved reserve quantities impact the Company's depreciation, depletion and amortization expense since the Company uses the units-of-production method to amortize its oil and natural gas properties. The proved reserves are also used as the basis for the disclosures in Item 8 - Supplementary Financial Information and are the underlying basis of the "ceiling test" for the Company's oil and natural gas properties.

The Company uses the full-cost method of accounting for its exploration and production activities. Under this method, capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, 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 flows associated with asset retirement obligations that have been accrued on the balance sheet. Judgments and assumptions are made when estimating and valuing proved reserves. Various factors, including lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in future noncash write-downs of the Company's oil and natural gas properties.

SEC Defined Prices for each quarter in 2014 were as follows:

SEC Defined Prices for the 12 months ended	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
December 31, 2014	$ 94.99	$ 4.34	$ 7.71
September 30, 2014	99.08	4.24	7.60
June 30, 2014	100.27	4.10	7.47
March 31, 2014	98.46	3.99	7.33

For purposes of comparison, first-of-the-month prices were as follows:

	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)	Ventura Gas Price (per MMBtu)
January 2015	$ 53.27	$ 3.00	$ 3.06
February 2015	48.24	2.68	2.78

Given the current oil and natural gas pricing environment, the Company believes it is likely it will have noncash write-downs of its oil and natural gas properties in future quarters until such time as commodity prices begin to recover.

Impairment of long-lived assets and intangibles

The Company reviews the carrying values of its long-lived assets and intangibles, excluding 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 15 . 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, 2014 , 2013 , and 2012 , there were no significant impairment losses recorded. At December 31, 2014 , 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 2014 . 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 2014 .

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 healthcare 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 healthcare 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 $1.5 million (after tax) for the year ended December 31, 2014 .

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 healthcare 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 16 .

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 $4.2 million for the year ended December 31, 2014 .

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.

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, 2014 , the Company had cash and cash equivalents of $81.9 million and available capacity of $677.3 million under the outstanding credit facilities of the Company and its subsidiaries. The Company expects to meet its obligations for debt maturing within one year from various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt and the Company's equity securities.

Cash flows

Operating activities The changes in cash flows from operating activities generally follow the results of operations as discussed in Financial and Operating Data and also are affected by changes in working capital.

Cash flows provided by operating activities in 2014 decreased $126.4 million from 2013. The decrease was primarily due to higher working capital requirements of $131.9 million, primarily at the exploration and production and construction services businesses.

Cash flows provided by operating activities in 2013 increased $157.5 million from 2012. The increase was primarily due to lower working capital requirements of $132.9 million, primarily at the exploration and production and construction materials and contracting businesses and higher income from continuing operations, largely at the exploration and production business.

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

Cash flows used in investing activities in 2013 decreased $105.3 million from 2012 primarily due to higher proceeds from the sale of properties, largely at the exploration and production business, as well as lower acquisition-related capital expenditures, primarily at the pipeline and energy services business. Partially offsetting the decrease in cash flows used in investing activities was higher ongoing capital expenditures of $36.5 million, largely related to Dakota Prairie Refinery at the pipeline and energy services business and electric generation projects at the electric business, partially offset by lower capital expenditures at the exploration and production business.

Financing activities 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 $54.9 million. Partially offsetting this increase were higher dividends paid in 2014 compared to 2013 due to the acceleration of the first quarter 2013 quarterly common stock dividend to 2012.

Cash flows provided by financing activities in 2013 decreased $152.8 million from 2012, primarily due to higher repayment of long-term debt of $284.9 million. Partially offsetting the decrease in cash flows provided by financing activities were lower dividends paid of $61.4 million resulting from the Company accelerating the payment date for the quarterly common stock dividend from January 1, 2013 to December 31, 2012; higher issuance of long-term debt of $40.0 million; as well as a cash contribution of $27.0 million related to the noncontrolling interest.

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, 2014 , the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $121.0 million . Pretax pension expense reflected in the years ended December 31, 2014 , 2013 and 2012 , was $1.1 million , $3.0 million and $204,000 , respectively. The Company's pension expense is currently projected to be approximately $3.0 million to $4.0 million in 2015 . Funding for the pension plans is actuarially determined. The minimum required contributions for 2014 , 2013 and 2012 were approximately $10.8 million , $13.2 million and $16.1 million , respectively. For more information on the Company's pension plans, see Item 8 - Note 16 .

Capital expenditures

The Company's capital expenditures for 2012 through 2014 and as anticipated for 2015 through 2017 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2012	2013	**2014**	2015	2016	2017
			(In millions)			
Capital expenditures:						
Electric	$ 112	$ 169	**$ 185**	$ 319	$ 172	$ 177
Natural gas distribution	130	101	**121**	159	191	158
Pipeline and energy services**	134	127	**177**	111	423	336
Exploration and production***	554	391	**601**	111	—	—
Construction materials and contracting	45	35	**38**	49	206	123
Construction services	15	15	**27**	24	82	72
Other	1	2	**2**	5	4	2
Net proceeds from sale or disposition of property and other	(57)	(112)	**(307)**	(86)	(4)	(7)
Net capital expenditures	934	728	**844**	692	1,074	861
Retirement of long-term debt	139	424	**369**	269	294	51
	$ 1,073	$ 1,152	**$ 1,213**	$ 961	$ 1,368	$ 912

* 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.

** Amounts include the Company's share of capital expenditures related to Dakota Prairie Refinery, as discussed in Prospective Information and Item 8 - Note 19 .

*** Future exploration and production capital expenditures are dependent upon the timing of marketing and sale. Sale proceeds for the business are excluded from capital expenditure projections.

Capital expenditures for 2014 , 2013 and 2012 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 $(61.2) million in 2014 , $(56.8) million in 2013 and $33.7 million in 2012 .

The 2014 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 2015 through 2017 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
- Further development of existing properties at the exploration and production segment
- Power generation and transmission opportunities, including certain costs for additional electric generating capacity and purchase agreement of electric wind generation
- Environmental upgrades
- Potential acquisitions at the construction materials and contracting and construction services segments
- The Company's proportionate share of Dakota Prairie Refinery at the pipeline and energy services segment
- Construction of a second 20,000-barrel-per-day topping plant at the pipeline and energy services segment, currently under evaluation
- 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 2015 through 2017 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.

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, 2014 . In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For more information on the covenants, certain other conditions and cross-default provisions, see Item 8 - Note 9 .

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

Company	Facility		Facility Limit			Amount Outstanding			Letters of Credit		Expiration Date
						(In millions)					
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$	175.0		$	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)	$	21.0		$	—		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (f)	$	650.0		$	211.0	(b)	$	—		5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement	$	50.0	(g)	$	—		$	1.0	(d)	12/1/15

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option 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) An outstanding letter of credit reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90.0 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $800.0 million). There were no amounts outstanding under the credit agreement.
(g) Certain provisions allow for increased borrowings up to a maximum of $75.0 million.

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

The following includes information related to the preceding table.

MDU Resources Group, Inc. On May 8, 2014, the Company amended the revolving credit agreement to increase the borrowing limit to $175.0 million and extend the termination date to May 8, 2019. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in the Company's credit ratings have not limited, nor are currently expected to limit, the Company's ability to access the capital markets. If the Company were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

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

The Company's coverage of fixed charges including preferred stock dividends was 4.5 times and 4.8 times for the 12 months ended December 31, 2014 and 2013 .

Total equity as a percent of total capitalization was 61 percent and 60 percent at December 31, 2014 and 2013 . This ratio is calculated as the Company's total equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus total equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

On May 20, 2013, the Company entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 7.5 million shares of the Company's common stock. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement. Sales of such common stock may not be made after February 28, 2016. Proceeds from the shares of common stock under the agreement have been and are expected to be used for corporate development purposes and other general corporate purposes. Under the Equity Distribution Agreement, the Company issued 3.9 million shares of stock during 2014 , receiving net proceeds of $130.1 million . Since inception of the Equity Distribution Agreement, the Company has issued a cumulative total of 4.4 million shares of stock receiving net proceeds of $144.7 million through December 31, 2014.

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. On May 8, 2014, Centennial entered into an amended and restated revolving credit agreement which increased the borrowing limit to $650.0 million and extended the termination date to May 8, 2019. 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, 2014 , which reduced capacity under this uncommitted private shelf agreement.

Dakota Prairie Refining, LLC On December 1, 2014, Dakota Prairie Refining entered into a $50.0 million revolving credit agreement with an expiration date of December 1, 2015. This credit agreement is used to meet the operational needs of Dakota Prairie Refining.

Off balance sheet arrangements

In connection with the sale of the Brazilian Transmission Lines, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines. For more information, see Item 8 - Note 4 .

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 9 and 19 . At December 31, 2014 , the Company's commitments under these obligations were as follows:

	2015	2016	2017	2018	2019	Thereafter	Total
				(In millions)			
Long-term debt	$ 269.4	$ 293.8	$ 51.0	$ 148.2	$ 345.7	$ 986.6	$ 2,094.7
Estimated interest payments*	92.3	71.1	61.9	60.1	51.6	472.4	809.4
Operating leases	48.1	43.5	34.3	28.1	19.7	78.7	252.4
Purchase commitments	694.7	304.6	161.0	91.0	86.4	910.6	2,248.3
	$ 1,104.5	$ 713.0	$ 308.2	$ 327.4	$ 503.4	$ 2,448.3	$ 5,404.8

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

At December 31, 2014 , the Company had total liabilities of $92.8 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was $13.7 million at December 31, 2014 , 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 10 .

Not reflected in the previous table are $137,000 in uncertain tax positions. For more information, see Item 8 - Note 14 .

The Company's minimum funding requirements for its defined benefit pension plans for 2015 , which are not reflected in the previous table, are $3.9 million . For information on potential contributions above the minimum funding requirements, see Item 8 - Note 16 .

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 16 .

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2014 , 2013 or 2012 .

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 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 7 .

Commodity price risk

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

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

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

The following table summarizes derivative agreements entered into by Fidelity as of December 31, 2013. These agreements call for Fidelity to receive fixed prices and pay variable prices.

	(Forward notional volume and fair value in thousands)		
	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Oil swap agreements maturing in 2014	$ 94.74	2,911	$ (4,771)
Natural gas swap agreements maturing in 2014	$ 4.10	14,600	$ (1,265)
Natural gas swap agreement maturing in 2015	$ 4.28	3,650	$ 503

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, 2014 and 2013 , 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, 2014 .

	2015	2016	2017	2018	2019	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 266.4	$ 288.6	$ 43.5	$ 108.5	$ 51.2	$ 955.1	$ 1,713.3	$ 1,859.8
Weighted average interest rate	5.7%	6.4%	6.3%	6.1%	4.3%	5.1%	5.5%	—
Variable rate	$ 3.0	$ 5.2	$ 7.5	$ 39.7	$ 294.5	$ 31.5	$ 381.4	$ 379.6
Weighted average interest rate	1.2%	1.8%	2.1%	2.6%	.4%	2.5%	.9%	—

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, 2014 . 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, 2014 .

The effectiveness of the Company's internal control over financial reporting as of December 31, 2014 , 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 President and Chief Executive Officer	Doran N. Schwartz Vice President and Chief Financial Officer

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, 2014 and 2013 , 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, 2014 . 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, 2014 and 2013 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 , 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, 2014 , 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 20, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 20, 2015

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, 2014 , 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, 2014 , 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, 2014 of the Company and our report dated February 20, 2015 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 20, 2015

Consolidated Statements of Income

Years ended December 31,		2014		2013		2012
		(In thousands, except per share amounts)				
Operating revenues:						
Electric, natural gas distribution and pipeline and energy services	**$**	**1,366,356**	$	1,264,574	$	1,131,626
Exploration and production, construction materials and contracting, construction services and other		**3,304,202**		3,197,830		2,943,805
Total operating revenues		**4,670,558**		4,462,404		4,075,431
Operating expenses:						
Fuel and purchased power		**89,312**		83,528		72,380
Purchased natural gas sold		**570,041**		505,065		425,220
Operation and maintenance:						
Electric, natural gas distribution and pipeline and energy services		**303,822**		269,825		254,194
Exploration and production, construction materials and contracting, construction services and other		**2,625,228**		2,535,872		2,377,285
Depreciation, depletion and amortization		**401,368**		386,856		359,205
Taxes, other than income		**192,562**		188,359		176,140
Write-downs of oil and natural gas properties (Note 1)		**—**		—		391,800
Total operating expenses		**4,182,333**		3,969,505		4,056,224
Operating income		**488,225**		492,899		19,207
Earnings (loss) from equity method investments		**(41)**		(132)		5,383
Other income		**9,962**		6,768		6,642
Interest expense		**87,016**		83,917		76,699
Income (loss) before income taxes		**411,130**		415,618		(45,467)
Income taxes		**119,969**		136,736		(31,146)
Income (loss) from continuing operations		**291,161**		278,882		(14,321)
Income (loss) from discontinued operations, net of tax (Note 3)		**3,177**		(312)		13,567
Net income (loss)		**294,338**		278,570		(754)
Net loss attributable to noncontrolling interest		**(3,895)**		(363)		—
Dividends declared on preferred stocks		**685**		685		685
Earnings (loss) on common stock	**$**	**297,548**	$	278,248	$	(1,439)
Earnings (loss) per common share - basic:						
Earnings (loss) before discontinued operations	**$**	**1.53**	$	1.47	$	(.08)
Discontinued operations, net of tax		**.02**		—		.07
Earnings (loss) per common share - basic	**$**	**1.55**	$	1.47	$	(.01)
Earnings (loss) per common share - diluted:						
Earnings (loss) before discontinued operations	**$**	**1.53**	$	1.47	$	(.08)
Discontinued operations, net of tax		**.02**		—		.07
Earnings (loss) per common share - diluted	**$**	**1.55**	$	1.47	$	(.01)
Weighted average common shares outstanding - basic		**192,507**		188,855		188,826
Weighted average common shares outstanding - diluted		**192,587**		189,693		188,826

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

Consolidated Statements of Comprehensive Income

Years ended December 31,	2014	2013	2012
		(In thousands)	
Net income (loss)	$ **294,338**	$ 278,570	$ (754)
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $0, $(3,116) and $4,829 in 2014, 2013 and 2012, respectively	**—**	(5,594)	8,497
Reclassification adjustment for (gain) loss on derivative instruments included in net income, net of tax of $413, $(2,548) and $(5,141) in 2014, 2013 and 2012, respectively	**694**	(4,189)	(8,754)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**694**	(9,783)	(257)
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $(7,665), $11,818 and $(2,060) in 2014, 2013 and 2012, respectively	**(12,409)**	18,539	(3,106)
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $492, $1,276 and $1,379 in 2014, 2013 and 2012, respectively	**796**	2,001	2,079
Reclassification of postretirement liability adjustment to regulatory asset, net of tax of $4,509, $0 and $0 in 2014, 2013 and 2012, respectively	**7,202**	—	—
Postretirement liability adjustment	**(4,411)**	20,540	(1,027)
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $(99), $(177) and $(296) in 2014, 2013 and 2012, respectively	**(162)**	(299)	(476)
Reclassification adjustment for (gain) loss on foreign currency translation adjustment included in net income, net of tax of $0, $70 and $2 in 2014, 2013 and 2012, respectively	**—**	143	3
Foreign currency translation adjustment	**(162)**	(156)	(473)
Net unrealized gain (loss) on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(83), $(105) and $(52) in 2014, 2013 and 2012, respectively	**(154)**	(194)	(97)
Reclassification adjustment for loss on available-for-sale investments included in net income, net of tax of $73, $59 and $72 in 2014, 2013 and 2012, respectively	**135**	109	134
Net unrealized gain (loss) on available-for-sale investments	**(19)**	(85)	37
Other comprehensive income (loss)	**(3,898)**	10,516	(1,720)
Comprehensive income (loss)	**290,440**	289,086	(2,474)
Comprehensive loss attributable to noncontrolling interest	**(3,895)**	(363)	—
Comprehensive income (loss) attributable to common stockholders	$ **294,335**	$ 289,449	$ (2,474)

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

Consolidated Balance Sheets

December 31,		2014		2013
		(In thousands, except shares and per share amounts)		
Assets				
Current assets:				
Cash and cash equivalents	$	**81,855**	$	45,225
Receivables, net		**693,318**		713,067
Inventories		**300,811**		282,391
Deferred income taxes		**23,806**		25,048
Commodity derivative instruments		**18,335**		1,447
Prepayments and other current assets		**76,848**		49,510
Total current assets		**1,194,973**		1,116,688
Investments		**117,920**		112,939
Property, plant and equipment (Note 1)		**9,693,171**		8,803,866
Less accumulated depreciation, depletion and amortization		**4,166,407**		3,872,487
Net property, plant and equipment		**5,526,764**		4,931,379
Deferred charges and other assets:				
Goodwill (Note 5)		**635,204**		636,039
Other intangible assets, net (Note 5)		**9,840**		13,099
Other		**325,277**		251,188
Total deferred charges and other assets		**970,321**		900,326
Total assets	$	**7,809,978**	$	7,061,332
Liabilities and Equity				
Current liabilities:				
Short-term borrowings (Note 9)	$	**—**	$	11,500
Long-term debt due within one year		**269,449**		12,277
Accounts payable		**382,671**		404,961
Taxes payable		**45,631**		74,175
Dividends payable		**35,607**		33,737
Accrued compensation		**62,775**		69,661
Commodity derivative instruments		**—**		7,483
Other accrued liabilities		**172,561**		171,106
Total current liabilities		**968,694**		784,900
Long-term debt (Note 9)		**1,825,278**		1,842,286
Deferred credits and other liabilities:				
Deferred income taxes		**952,413**		859,306
Other liabilities		**813,809**		718,938
Total deferred credits and other liabilities		**1,766,222**		1,578,244
Commitments and contingencies (Notes 16, 18 and 19)				
Equity:				
Preferred stocks (Note 11)		**15,000**		15,000
Common stockholders' equity:				
Common stock (Note 12) Authorized - 500,000,000 shares, $1.00 par value Issued - 194,754,812 shares in 2014 and 189,868,780 shares in 2013		**194,755**		189,869
Other paid-in capital		**1,207,188**		1,056,996
Retained earnings		**1,762,827**		1,603,130
Accumulated other comprehensive loss		**(42,103)**		(38,205)
Treasury stock at cost - 538,921 shares		**(3,626)**		(3,626)
Total common stockholders' equity		**3,119,041**		2,808,164
Total stockholders' equity		**3,134,041**		2,823,164
Noncontrolling interest		**115,743**		32,738
Total equity		**3,249,784**		2,855,902
Total liabilities and equity	$	**7,809,978**	$	7,061,332

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

Consolidated Statements of Equity

Years ended December 31, 2014, 2013 and 2012

	Preferred Stock		Common Stock					Treasury Stock			
	Shares	Amount	Shares	Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Shares	Amount	Noncontrolling Interest	Total
					(In thousands, except shares)						
Balance at December 31, 2011	150,000	$ 15,000	189,332,485	$ 189,332	$ 1,035,739	$ 1,586,123	$ (47,001)	(538,921)	$ (3,626)	$ —	$ 2,775,567
Net loss	—	—	—	—	—	(754)	—	—	—	—	(754)
Other comprehensive loss	—	—	—	—	—	—	(1,720)	—	—	—	(1,720)
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(127,538)	—	—	—	—	(127,538)
Stock-based compensation	—	—	25,743	26	5,094	—	—	—	—	—	5,120
Net tax deficit on stock-based compensation	—	—	—	—	(1,958)	—	—	—	—	—	(1,958)
Issuance of common stock	—	—	11,222	11	205	—	—	—	—	—	216
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)	—	2,648,248
Net income (loss)	—	—	—	—	—	278,933	—	—	—	(363)	278,570
Other comprehensive income	—	—	—	—	—	—	10,516	—	—	—	10,516
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(132,264)	—	—	—	—	(132,264)
Stock-based compensation	—	—	—	—	5,281	—	—	—	—	—	5,281
Net tax deficit on stock-based compensation	—	—	—	—	(1,419)	—	—	—	—	—	(1,419)
Issuance of common stock	—	—	499,330	500	14,054	—	—	—	—	—	14,554
Contribution from noncontrolling interest	—	—	—	—	—	—	—	—	—	33,101	33,101
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	2,855,902
Net income (loss)	—	—	—	—	—	298,233	—	—	—	(3,895)	294,338
Other comprehensive loss	—	—	—	—	—	—	(3,898)	—	—	—	(3,898)
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(137,851)	—	—	—	—	(137,851)
Stock-based compensation	—	—	—	—	6,191	—	—	—	—	—	6,191
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	326,122	326	(5,890)	—	—	—	—	—	(5,564)
Excess tax benefit on stock-based compensation	—	—	—	—	4,729	—	—	—	—	—	4,729
Issuance of common stock	—	—	4,559,910	4,560	145,162	—	—	—	—	—	149,722
Contribution from noncontrolling interest	—	—	—	—	—	—	—	—	—	86,900	86,900
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**	**$ 3,249,784**

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

Consolidated Statements of Cash Flows

Years ended December 31,	2014	2013	2012
		(In thousands)	
Operating activities:			
Net income (loss)	**$ 294,338**	$ 278,570	$ (754)
Income (loss) from discontinued operations, net of tax	**3,177**	(312)	13,567
Income (loss) from continuing operations	**291,161**	278,882	(14,321)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**401,368**	386,856	359,205
Earnings (loss), net of distributions, from equity method investments	**550**	2,281	(618)
Deferred income taxes	**87,015**	86,778	(7,503)
Unrealized (gain) loss on commodity derivatives	**(23,400)**	6,267	624
Write-downs of oil and natural gas properties (Note 1)	**—**	—	391,800
Excess tax benefit on stock-based compensation	**(4,729)**	—	(26)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**6,166**	(40,669)	(13,416)
Inventories	**(18,738)**	30,452	(42,334)
Other current assets	**(25,997)**	(9,474)	297
Accounts payable	**(45,065)**	15,084	6,352
Other current liabilities	**(23,515)**	29,392	(59,001)
Other noncurrent changes	**(29,193)**	(43,937)	(33,639)
Net cash provided by continuing operations	**615,623**	741,912	587,420
Net cash provided by (used in) discontinued operations	**159**	281	(2,680)
Net cash provided by operating activities	**615,782**	742,193	584,740
Investing activities:			
Capital expenditures	**(972,102)**	(909,400)	(872,920)
Acquisitions, net of cash acquired	**(209,213)**	—	(67,261)
Net proceeds from sale or disposition of property and other	**276,415**	124,541	40,110
Investments	**709**	302	9,725
Proceeds from sale of equity method investments	**—**	1,896	2,394
Net cash used in continuing operations	**(904,191)**	(782,661)	(887,952)
Net cash provided by discontinued operations	**—**	—	—
Net cash used in investing activities	**(904,191)**	(782,661)	(887,952)
Financing activities:			
Issuance of short-term borrowings	**—**	9,500	20,100
Repayment of short-term borrowings	**(11,500)**	—	—
Issuance of long-term debt	**606,084**	507,924	467,957
Repayment of long-term debt	**(368,803)**	(423,707)	(138,775)
Proceeds from issuance of common stock	**150,060**	14,554	88
Dividends paid	**(136,712)**	(98,405)	(159,768)
Excess tax benefit on stock-based compensation	**4,729**	—	26
Tax withholding on stock-based compensation	**(5,564)**	—	—
Contribution from noncontrolling interest	**86,900**	27,000	—
Net cash provided by continuing operations	**325,194**	36,866	189,628
Net cash provided by discontinued operations	**—**	—	—
Net cash provided by financing activities	**325,194**	36,866	189,628
Effect of exchange rate changes on cash and cash equivalents	**(155)**	(215)	(146)
Increase (decrease) in cash and cash equivalents	**36,630**	(3,817)	(113,730)
Cash and cash equivalents - beginning of year	**45,225**	49,042	162,772
Cash and cash equivalents - end of year	**$ 81,855**	$ 45,225	$ 49,042

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 energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15 . 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 6 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, 2014 , up to the date of issuance of these consolidated financial statements.

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 $30.9 million and $36.4 million at December 31, 2014 and 2013 , respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts at December 31, 2014 and 2013 , was $9.5 million and $10.1 million , respectively.

Inventories and natural gas in storage

Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

		2014		2013
		(In thousands)		
Aggregates held for resale	**$**	**108,161**	$	101,568
Materials and supplies		**65,683**		69,808
Asphalt oil		**42,135**		38,099
Merchandise for resale		**24,420**		21,720
Natural gas in storage (current)		**19,302**		16,417
Other		**41,110**		34,779
Total	**$**	**300,811**	$	282,391

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $49.3 million and $48.3 million at December 31, 2014 and 2013 , respectively.

Investments

The Company's investments include its equity method and cost method investments as discussed in Note 4 , the cash surrender value of life insurance policies, an insurance contract, mortgage-backed securities and U.S. Treasury securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. 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 8 and 16 .

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, except for exploration and production properties as described in Oil and natural gas properties in this note, 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, at the exploration and production segment only on costs that have been excluded from the full cost amortization pool and 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:

		2014		2013		2012
				(In thousands)		
Interest capitalized	**$**	**8,586**	$	6,033	$	8,659
AFUDC - borrowed	**$**	**3,022**	$	2,767	$	2,483
AFUDC - equity	**$**	**5,803**	$	3,322	$	4,530

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, and exploration and production properties, which are amortized on the units-of-production method based on total proved reserves. 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.

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

	2014	2013	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	**$ 627,952**	$ 570,394	42
Distribution	**343,692**	308,202	39
Transmission	**229,997**	196,824	48
Construction in progress	**150,445**	141,365	-
Other	**105,015**	99,037	15
Natural gas distribution:			
Distribution	**1,481,390**	1,384,587	40
Construction in progress	**59,310**	46,763	-
Other	**364,059**	345,551	27
Pipeline and energy services:			
Transmission	**449,276**	418,594	53
Gathering	**39,595**	39,597	20
Storage	**43,994**	42,939	60
Construction in progress	**5,386**	6,937	-
Other	**39,910**	39,504	33
Nonregulated:			
Pipeline and energy services:			
Midstream	**227,598**	213,063	16
Construction in progress	**314,304**	188,641	-
Other	**100,170**	12,897	18
Exploration and production:			
Oil and natural gas properties	**3,337,177**	3,017,879	*
Other	**65,702**	42,969	8
Construction materials and contracting:			
Land	**125,372**	125,551	-
Buildings and improvements	**70,566**	70,000	19
Machinery, vehicles and equipment	**921,564**	906,774	12
Construction in progress	**8,709**	13,315	-
Aggregate reserves	**403,731**	394,715	**
Construction services:			
Land	**5,265**	4,821	-
Buildings and improvements	**17,936**	16,628	20
Machinery, vehicles and equipment	**112,973**	105,991	6
Other	**8,221**	7,508	4
Other:			
Land	**2,837**	2,837	-
Other	**48,100**	47,160	23
Eliminations	**(17,075)**	(7,177)	
Less accumulated depreciation, depletion and amortization	**4,166,407**	3,872,487	
Net property, plant and equipment	**$ 5,526,764**	$ 4,931,379	

* Amortized on the units-of-production method based on total proved reserves at a BOE average rate of $21.17 , $17.41 and $15.28 for the years ended December 31, 2014 , 2013 and 2012 , respectively. Includes oil and natural gas properties accounted for under the full-cost method, of which $132.1 million and $124.9 million were excluded from amortization at December 31, 2014 and 2013 , respectively.

** 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 and oil and natural gas properties, 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 2013 and 2012 , the Company recognized impairments of $9.0 million (after tax) and $1.7 million (after tax), respectively, which are recorded in operation and maintenance expense on the Consolidated Statements of Income. The impairments are related to coalbed natural gas gathering assets located in Wyoming and Montana where there has been a significant decline in natural gas development and production activity largely due to low natural gas prices. The coalbed natural gas gathering assets were written down to fair value that was determined using the income approach. For more information on this nonrecurring fair value measurement, see Note 8 .

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 15 . 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, 2014 , 2013 and 2012 , there were no significant impairment losses recorded. At December 31, 2014 , 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 2014 . 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.

Oil and natural gas properties

The Company uses the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, 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.

SEC Defined Prices for each quarter in 2014 were as follows:

SEC Defined Prices for the 12 months ended		NYMEX Oil Price (per Bbl)		Henry Hub Gas Price (per MMBtu)		Ventura Gas Price (per MMBtu)
December 31, 2014	$	94.99	$	4.34	$	7.71
September 30, 2014		99.08		4.24		7.60
June 30, 2014		100.27		4.10		7.47
March 31, 2014		98.46		3.99		7.33

For purposes of comparison, first-of-the-month prices were as follows:

		NYMEX Oil Price (per Bbl)		Henry Hub Gas Price (per MMBtu)		Ventura Gas Price (per MMBtu)
January 2015	$	53.27	$	3.00	$	3.06
February 2015		48.24		2.68		2.78

Given the current oil and natural gas pricing environment, the Company believes it is likely it will have noncash write-downs of its oil and natural gas properties in future quarters until such time as commodity prices begin to recover.

At December 31, 2014 and 2013 , the Company's full-cost ceiling exceeded the Company's capitalized cost. Various factors, including lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in future noncash write-downs of the Company's oil and natural gas properties.

The Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at September 30, 2012 and December 31, 2012. SEC Defined Prices, adjusted for market differentials, are used to calculate the ceiling test. SEC Defined Prices as of September 30, 2012 and December 31, 2012, were $94.97 per Bbl for NYMEX oil and $2.83 per MMBtu for Henry Hub natural gas and $94.71 per Bbl for NYMEX oil and $2.76 per MMBtu for Henry Hub natural gas, respectively. Accordingly, the Company was required to write down its oil and natural gas producing properties. The noncash write-downs amounted to $160.1 million and $231.7 million ($100.9 million and $145.9 million after tax) for the three months ended September 30, 2012 and December 31, 2012, respectively.

The Company hedged a portion of its oil and natural gas production and the effects of the cash flow hedges were used in determining the full-cost ceiling at September 30, 2012 and December 31, 2012. The Company would have recognized additional write-downs of its oil and natural gas properties of $19.5 million ($12.3 million after tax) at September 30, 2012, and $20.8 million ($13.1 million after tax) at December 31, 2012, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 7 .

The following table summarizes the Company's oil and natural gas properties not subject to amortization at December 31, 2014 , in total and by the year in which such costs were incurred:

			Year Costs Incurred						
		Total		2014		2013		2012	2011 and prior
					(In thousands)				
Acquisition	$	97,795	$	82,233	$	1,528	$	475	$ 13,559
Development		14,312		3,361		9,928		484	539
Exploration		18,221		10,961		3,126		3,885	249
Capitalized interest		1,813		1,343		203		67	200
Total costs not subject to amortization	$	132,141	$	97,898	$	14,785	$	4,911	$ 14,547

Costs not subject to amortization as of December 31, 2014 , consisted primarily of unevaluated leaseholds and development costs in the Powder River Basin and the Paradox Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

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 $99.7 million and $107.4 million at December 31, 2014 and 2013 , 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:

		2014		2013
		(In thousands)		
Costs and estimated earnings in excess of billings on uncompleted contracts	**$**	**58,243**	$	60,828
Billings in excess of costs and estimated earnings on uncompleted contracts	**$**	**47,011**	$	84,189

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

		2014		2013
		(In thousands)		
Short-term retainage*	**$**	**47,551**	$	55,906
Long-term retainage**		**1,053**		4,229
Total retainage	**$**	**48,604**	$	60,135

* 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 at Fidelity 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 at Fidelity 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 7 .

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 10 .

Legal costs

The Company expenses external legal fees as they are incurred.

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 within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $13.2 million and $16.9 million at December 31, 2014 and 2013 , respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $19.6 million and $12.1 million at December 31, 2014 and 2013 , 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.

Foreign currency translation adjustment

The functional currency of the Company's investment in ECTE, as discussed in Note 4 , is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using an average of the daily exchange rates.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity would be recorded in income.

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 per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding performance share awards. In 2014 and 2013, there were no shares excluded from the calculation of diluted earnings per share. Diluted loss per common share for the year ended December 31, 2012, was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the year. Due to the loss on common stock for the year ended December 31, 2012, the effect of outstanding performance share awards was excluded from the computation of diluted loss per common share as their effect was antidilutive. 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:

	2014	2013	2012
		(In thousands)	
Weighted average common shares outstanding - basic	**192,507**	188,855	188,826
Effect of dilutive performance share awards	**80**	838	—
Weighted average common shares outstanding - diluted	**192,587**	189,693	188,826
Shares excluded from the calculation of diluted earnings per share	**—**	—	58

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 long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; oil, NGL and natural gas proved reserves; 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; the valuation of stock-based compensation; and the fair value of derivative instruments. 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.

Cash flow information

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

	2014	2013	2012
		(In thousands)	
Interest, net of amount capitalized	**$ 81,351**	$ 81,689	$ 74,378
Income taxes paid, net	**$ 69,087**	$ 24,857	$ 3,277

Noncash investing transactions at December 31 were as follows:

	2014	2013	2012
		(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 103,327**	$ 67,129	$ 76,205

New accounting standards

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

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 7 .

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2014 , 2013 and 2012 , 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, 2012	$ 6,018	$ (54,347)	$ (511)	$ 119	$ (48,721)
Other comprehensive income (loss) before reclassifications	(5,594)	18,539	(299)	(194)	12,452
Amounts reclassified from accumulated other comprehensive loss	(4,189)	2,001	143	109	(1,936)
Net current-period other comprehensive income (loss)	(9,783)	20,540	(156)	(85)	10,516
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)**

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

	2014	2013	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for gain (loss) on derivative instruments included in net income:			
Commodity derivative instruments	**$ (468)**	$ 7,803	Operating revenues
Interest rate derivative instruments	**(639)**	(1,066)	Interest expense
	(1,107)	6,737	
	413	(2,548)	Income taxes
	(694)	4,189	
Amortization of postretirement liability losses included in net periodic benefit cost	**(1,288)**	(3,277)	(a)
	492	1,276	Income taxes
	(796)	(2,001)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income	**—**	(213)	Earnings (loss) from equity method investments
	—	70	Earnings (loss) from equity method investments
	—	(143)	
Reclassification adjustment for loss on available-for-sale investments included in net income	**(208)**	(168)	Other income
	73	59	Income taxes
	(135)	(109)	
Total reclassifications	**$ (1,625)**	$ 1,936	

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

Note 2 - Acquisitions

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.

In 2012, the Company acquired a 50 percent undivided interest in natural gas and oil midstream assets in western North Dakota. The acquisition includes a natural gas processing plant and a natural gas gathering pipeline system, along with an oil gathering system, an oil storage terminal and an oil pipeline. The total purchase consideration for acquisitions was approximately $67.5 million , including the Company's interest in the above facilities and contingent consideration related to an acquisition made prior to 2012. The Company recognizes its proportionate share of the assets, liabilities, revenues and expenses related to the natural gas and oil midstream assets acquisition.

The acquisitions were accounted for under the acquisition method of accounting and, accordingly, the acquired assets and liabilities assumed have been recorded at their respective fair values as of the date of acquisition. The results of operations of the acquired businesses and properties are included in the financial statements since the date of each acquisition. 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.

Note 3 - Discontinued Operations

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In the second quarter of 2012, discontinued operations reflected the settlement of certain liabilities and estimated insurance recoveries resulting in a net benefit related to this matter. In the fourth quarter of 2012, the Company reversed its previously recorded accrual for the arbitration

charge due to a favorable court ruling, which was partially offset by the reversal of estimated insurance recoveries. The Company incurred legal expenses and had a benefit related to the resolution of this matter in the second quarter of 2014. The Company also had a benefit related to income taxes, including the resolution of certain income tax matters, in the fourth quarter of 2014. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category.

Note 4 - Equity Method Investments

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. At December 31, 2014 and 2013 , the Company had no significant equity method investments.

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

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale of its entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE. The Company's remaining interest in ECTE is being sold over a multi-year period. In August 2013 and 2012, and November 2011, the Company completed the sale of one-fourth of the remaining interest in each year. The Company recognized immaterial gains in 2013 and 2012. The Company's remaining ownership interest in ECTE at December 31, 2014 , accounted for under the cost method, was subsequently sold on January 26, 2015.

Note 5 - Goodwill and Other Intangible Assets

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 energy services	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 energy services segment, which occurred in prior periods.

The changes in the carrying amount of goodwill for the year ended December 31, 2013 , were as follows:

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

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

Other amortizable intangible assets at December 31 were as follows:

		2014		2013
		(In thousands)		
Customer relationships	$	21,310	$	21,310
Accumulated amortization		(15,556)		(13,726)
		5,754		7,584
Noncompete agreements		5,080		6,186
Accumulated amortization		(4,098)		(4,840)
		982		1,346
Other		10,921		10,995
Accumulated amortization		(7,817)		(6,826)
		3,104		4,169
Total	$	9,840	$	13,099

Amortization expense for amortizable intangible assets for the years ended December 31, 2014 , 2013 and 2012 , was $3.2 million , $4.0 million and $3.8 million , respectively. Estimated amortization expense for intangible assets is $2.5 million in 2015 , $2.1 million in 2016 , $1.9 million in 2017 , $1.0 million in 2018 , $900,000 in 2019 and $1.4 million thereafter.

Note 6 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period *		2014		2013
			(In thousands)		
Regulatory assets:					
Pension and postretirement benefits (a)	(e)	$	182,565	$	105,123
Taxes recoverable from customers (a)	Over plant lives		22,910		18,266
Manufactured gas plant sites remediation (a)	Up to 3 years		17,548		15,797
Natural gas costs recoverable through rate adjustments (b)	Up to 28 months		19,575		12,060
Long-term debt refinancing costs (a)	Up to 23 years		7,864		8,697
Costs related to identifying generation development (a)	Up to 12 years		4,165		4,512
Other (a) (b)	Largely within 1- 4 years		14,959		15,311
Total regulatory assets			269,586		179,766
Regulatory liabilities:					
Plant removal and decommissioning costs (c)			338,641		308,431
Taxes refundable to customers (c)			17,772		20,180
Natural gas costs refundable through rate adjustments (d)			13,238		16,932
Other (c) (d)			16,601		21,868
Total regulatory liabilities			386,252		367,411
Net regulatory position		$	(116,666)	$	(187,645)

* 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, 2014 and 2013 , approximately $229.6 million and $163.7 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 7 - 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. As of December 31, 2014 and 2013 , credit risk was not material.

Fidelity

At December 31, 2014 and 2013 , Fidelity held oil swap agreements with total forward notional volumes of 270,000 and 2.9 million Bbl, respectively, and natural gas swap agreements with total forward notional volumes of 5.0 million and 18.3 million MMBtu, respectively. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas on its forecasted sales of oil and natural gas production.

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

Certain of Fidelity's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. Fidelity had no derivative instruments that were in a liability position with credit-risk-related contingent features at December 31, 2014 . The aggregate fair value of Fidelity's derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2013 , was $7.5 million . The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2013 , was $7.5 million .

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, 2014 and 2013 , Centennial had no outstanding interest rate swap agreements.

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:

	2014	2013	2012
		(In thousands)	
Commodity derivatives designated as cash flow hedges:			
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	$ —	$ (6,153)	$ 10,209
Amount of (gain) loss reclassified from accumulated other comprehensive loss into operating revenues (effective portion), net of tax	295	(4,916)	(8,788)
Amount of loss recognized in operating revenues (ineffective portion), before tax	—	(1,422)	(730)
Interest rate derivatives designated as cash flow hedges:			
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	—	559	(1,712)
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	399	727	34
Amount of loss recognized in interest expense (ineffective portion), before tax	—	(769)	—
Commodity derivatives not designated as hedging instruments:			
Amount of gain (loss) recognized in operating revenues, before tax	23,400	(4,845)	106

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 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	Fair Value at December 31, 2013
		(In thousands)	
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 18,335	$ 1,447
	Other assets - noncurrent	—	503
Total asset derivatives		$ 18,335	$ 1,950

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

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

December 31, 2014	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
	(In thousands)		
Assets:			
Commodity derivatives	$ 18,335	$ —	$ 18,335
Total assets	$ 18,335	$ —	$ 18,335

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

Note 8 - 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 $65.8 million and $62.4 million as of December 31, 2014 and 2013 , respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2014 , 2013 and 2012, were $3.4 million , $13.5 million and $5.2 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, 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

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

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

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

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

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

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

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

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, 2014 and 2013 , there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at 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	$ —	$ 18,473	$ —	$ 18,473
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
Commodity derivative instruments	—	18,335	—	18,335
Total assets measured at fair value	$ —	$ 112,830	$ —	$ 112,830

* 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.

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

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

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

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The fair value was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt at December 31 was as follows:

	2014		2013	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 2,094,727**	**$ 2,239,445**	$ 1,854,563	$ 1,912,590

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

Note 9 - 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, 2014		Amount Outstanding at December 31, 2013		Letters of Credit at December 31, 2014		Expiration Date
						(In millions)				
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$ 175.0		$ 77.5	(b)	$ 78.9	(b)	$ —		5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0	(c)	$ —		$ 11.5		$ 2.2	(d)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$ 65.0	(e)	$ 21.0		$ 3.0		$ —		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (f)	$ 650.0		$ 211.0	(b)	$ 75.0	(b)	$ —		5/8/19
Dakota Prairie Refining, LLC	Revolving credit agreement	$ 50.0	(g)	$ —		$ —		$ 1.0	(d)	12/1/15

(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) An outstanding letter of credit reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90.0 million .
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $800.0 million). There were no amounts outstanding under the credit agreement.
(g) Certain provisions allow for increased borrowings up to a maximum of $75.0 million .

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 following includes information related to the preceding table.

Short-term borrowings

Dakota Prairie Refining, LLC On December 1, 2014, Dakota Prairie Refining entered into a $50.0 million revolving credit agreement with an expiration date of December 1, 2015.

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. On May 8, 2014, the Company amended the revolving credit agreement to increase the borrowing limit to $175.0 million and extend the termination date to May 8, 2019. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

The 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.

On January 15, 2015, Cascade issued $25.0 million of Senior Notes with due dates ranging from January 15, 2045 to January 15, 2055 at a weighted average interest rate of 4.2 percent.

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.

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. On May 8, 2014, Centennial entered into an amended and restated revolving credit agreement which increased the borrowing limit to $650.0 million and extended the termination date to May 8, 2019. 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.

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.

On January 9, 2015, Centennial amended its letter of credit agreement for the issuance of up to approximately $28.0 million of letters of credit to extend the termination date to January 11, 2016.

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, 2014 , 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:

	2014	2013
	(In thousands)	
Senior Notes at a weighted average rate of 5.43%, due on dates ranging from June 19, 2015 to November 24, 2055	**$ 1,636,662**	$ 1,545,078
Commercial paper at a weighted average rate of .37%, supported by revolving credit agreements	**288,500**	153,924
Term Loan Agreements at a weighted average rate of 2.12%, due on dates ranging from April 22, 2018 to April 22, 2023	**72,000**	75,000
Medium-Term Notes at a weighted average rate of 7.32%, due on dates ranging from September 15, 2027 to March 16, 2029	**35,000**	35,000
Other notes at a weighted average rate of 5.23%, due on dates ranging from September 1, 2020 to February 1, 2035	**39,662**	39,863
Credit agreements at a weighted average rate of 3.47%, due on dates ranging from February 10, 2015 to November 30, 2038	**22,939**	5,701
Discount	**(36)**	(3)
Total long-term debt	**2,094,727**	1,854,563
Less current maturities	**269,449**	12,277
Net long-term debt	**$ 1,825,278**	$ 1,842,286

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2014 , aggregate $269.4 million in 2015 ; $293.8 million in 2016 ; $51.0 million in 2017 ; $148.2 million in 2018 ; $345.7 million in 2019 and $986.6 million thereafter.

Note 10 - Asset Retirement Obligations

The Company records obligations related to the plugging and abandonment of oil and natural gas wells, 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:

	2014	2013
	(In thousands)	
Balance at beginning of year	**$ 98,529**	$ 102,545
Liabilities incurred	**5,416**	5,610
Liabilities acquired	**1,414**	—
Liabilities settled	**(18,388)**	(22,257)
Accretion expense	**4,605**	4,574
Revisions in estimates	**884**	7,671
Other	**379**	386
Balance at end of year	**$ 92,839**	$ 98,529

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.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2014 and 2013 , was $2.3 million and $4.1 million , respectively. The legally restricted assets consist primarily of money market funds and are reflected in other assets on the Consolidated Balance Sheets.

Note 11 - Preferred Stocks

Preferred stocks at December 31 were as follows:

		2014		2013
		(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 2014 , 2013 and 2012 , 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 12 - Common Stock

For the years 2014, 2013 and 2012, dividends declared on common stock were $.7150 , $.6950 and $.6750 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 to December 2014, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From January 2012 through December 2013, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2014 , there were 14.9 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 $2.3 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2014 . 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 $259 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, 2014 . 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 13 - 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, 2014 , there are 5.6 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense (after tax) was $4.4 million , $3.9 million and $4.0 million in 2014 , 2013 and 2012 , respectively.

As of December 31, 2014 , total remaining unrecognized compensation expense related to stock-based compensation was approximately $8.0 million (before income taxes) which will be amortized over a weighted average period of 1.6 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 43,088 shares with a fair value of $1.1 million , 36,713 shares with a fair value of $1.1 million and 53,888 shares with a fair value of $1.1 million issued under this plan during the years ended December 31, 2014 , 2013 and 2012 , respectively.

A key employee of the Company received an award of 43,103 shares of common stock under a long-term incentive plan with a fair value of $930,000 during the year ended December 31, 2012.

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, 2014 , were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2012	2012-2014	251,196
March 2013	2013-2015	240,419
February 2014	2014-2016	196,840

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 2014 , 2013 and 2012 were:

	2014			2013			2012		
Grant-date fair value			**$41.13**			$29.01			$17.18
Blended volatility range	**18.94%**	**–**	**20.43%**	16.10%	–	19.39%	24.29%	–	25.81%
Risk-free interest rate range	**.03%**	**–**	**.74%**	.09%	–	.40%	.10%	–	.35%
Discounted dividends per share			**$2.15**			$2.12			$1.19

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 2013 or 2012.

A summary of the status of the performance share awards for the year ended December 31, 2014 , was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	749,991	$	21.99
Granted	196,840		41.13
Additional performance shares earned	236,699		19.99
Vested	(491,213)		19.99
Forfeited	(3,862)		29.01
Nonvested at end of period	688,455	$	28.16

Note 14 - Income Taxes

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

		2014		2013		2012
				(In thousands)		
United States	**$**	**411,182**	$	415,202	$	(47,175)
Foreign		**(52)**		416		1,708
Income (loss) before income taxes from continuing operations	**$**	**411,130**	$	415,618	$	(45,467)

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

		2014		2013		2012
				(In thousands)		
Current:						
Federal	**$**	**32,726**	$	45,518	$	(26,858)
State		**5,390**		4,311		858
Foreign		**—**		(29)		(75)
		38,116		49,800		(26,075)
Deferred:						
Income taxes:						
Federal		**81,017**		78,953		(1,224)
State		**4,989**		8,031		(6,323)
Investment tax credit - net		**1,009**		(206)		44
		87,015		86,778		(7,503)
Change in uncertain tax positions		**(5,183)**		—		1,974
Change in accrued interest		**21**		158		458
Total income tax expense (benefit)	**$**	**119,969**	$	136,736	$	(31,146)

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

		2014		2013
		(In thousands)		
Deferred tax assets:				
Regulatory matters	$	134,567	$	125,607
Accrued pension costs		97,690		74,320
Alternative minimum tax credit carryforward		23,844		33,304
Compensation-related		38,654		31,550
Asset retirement obligations		34,296		29,578
Legal and environmental contingencies		10,049		10,710
Other		59,389		45,101
Total deferred tax assets		398,489		350,170
Deferred tax liabilities:				
Depreciation and basis differences on property, plant and equipment		906,455		813,597
Basis differences on oil and natural gas producing properties		270,939		266,168
Regulatory matters		97,521		64,914
Intangible asset amortization		22,505		13,579
Other		29,676		26,170
Total deferred tax liabilities		1,327,096		1,184,428
Net deferred income tax liability	$	(928,607)	$	(834,258)

As of December 31, 2014 and 2013 , no valuation allowance has been recorded associated with the previously identified deferred tax assets. The alternative minimum tax credit carryforwards do not expire.

The following table reconciles the change in the net deferred income tax liability from December 31, 2013 , to December 31, 2014 , to deferred income tax expense:

		2014
		(In thousands)
Change in net deferred income tax liability from the preceding table	$	94,349
Deferred taxes associated with other comprehensive loss		2,360
Other		(9,694)
Deferred income tax expense for the period	$	87,015

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

Years ended December 31,		2014			2013			2012	
		Amount	%		Amount	%		Amount	%
					(Dollars in thousands)				
Computed tax at federal statutory rate	$	143,895	35.0	$	145,466	35.0	$	(15,914)	35.0
Increases (reductions) resulting from:									
State income taxes, net of federal income tax		10,483	2.5		10,524	2.5		2,469	(5.4)
Domestic production activities		(5,460)	(1.3)		(677)	(.2)		—	—
Nonqualified benefit plans		(1,624)	(.4)		(5,173)	(1.2)		(2,359)	5.2
Depletion allowance		(4,010)	(1.0)		(3,764)	(.9)		(3,728)	8.2
Federal renewable energy credit		(3,655)	(.9)		(3,404)	(.8)		(3,401)	7.5
Deductible K-Plan dividends		(2,062)	(.5)		(1,593)	(.4)		(2,829)	6.2
AFUDC equity		(2,031)	(.5)		(1,074)	(.3)		(1,500)	3.3
Resolution of tax matters and uncertain tax positions		(7,367)	(1.8)		(859)	(.2)		2,559	(5.6)
Deferred tax rate changes		9	—		741	.2		(3,083)	6.8
Other		(8,209)	(1.9)		(3,451)	(.8)		(3,360)	7.3
Total income tax expense (benefit)	$	119,969	29.2	$	136,736	32.9	$	(31,146)	68.5

The income tax benefit in 2012 resulted largely from the Company's write-downs of oil and natural gas properties, as discussed in Note 1 .

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 $3.6 million at December 31, 2014 . The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2014 , was approximately $1.4 million .

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, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2007. The Company and the Internal Revenue Service have agreed to a settlement for the 2007 through 2009 tax years.

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

	2014	2013	2012
		(In thousands)	
Balance at beginning of year	**$ 14,914**	$ 14,914	$ 11,206
Additions for tax positions of prior years	**—**	—	3,708
Settlements	**(14,777)**	—	—
Balance at end of year	**$ 137**	$ 14,914	$ 14,914

Included in the balance of unrecognized tax benefits at December 31, 2013 , was $8.4 million of 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 $155,000 , including approximately $18,000 for the payment of interest and penalties at December 31, 2014 , and was $9.0 million , including approximately $2.5 million for the payment of interest and penalties at December 31, 2013 .

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2014 , will be settled in the next twelve months.

For the years ended December 31, 2014 , 2013 and 2012 , the Company recognized approximately $1.8 million , $1.2 million and $740,000 , respectively, in interest expense. Penalties were not material in 2014 , 2013 and 2012 . The Company recognized interest income of approximately $540,000 , $660,000 and $290,000 for the years ended December 31, 2014 , 2013 and 2012 , respectively. The Company had accrued liabilities of approximately $1.8 million and $2.8 million at December 31, 2014 and 2013 , respectively, for the payment of interest.

Note 15 - Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these operating segments is defined based on the reporting and review process used by the Company's chief executive officer. The vast majority of the Company's operations are located within the United States. The Company also has an investment in a foreign country, which consists of Centennial Resources' investment in ECTE. For more information, see Note 4 .

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

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

The exploration and production segment is engaged in oil and natural gas development and production activities in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States. The Company intends to market its exploration and production business in the future. The plan to market this business has been delayed due to low oil prices.

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

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

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

The information below follows the same accounting policies as described in 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:

		2014		2013		2012
				(In thousands)		
External operating revenues:						
Electric	**$**	**277,874**	$	257,260	$	236,895
Natural gas distribution		**921,986**		851,945		754,848
Pipeline and energy services		**166,496**		155,369		139,883
		1,366,356		1,264,574		1,131,626
Exploration and production		**500,526**		490,924		412,651
Construction materials and contracting		**1,740,089**		1,675,444		1,597,257
Construction services		**1,062,055**		1,029,909		932,013
Other		**1,532**		1,553		1,884
		3,304,202		3,197,830		2,943,805
Total external operating revenues	**$**	**4,670,558**	$	4,462,404	$	4,075,431
Intersegment operating revenues:						
Electric	**$**	**—**	$	—	$	—
Natural gas distribution		**—**		—		—
Pipeline and energy services		**49,372**		46,699		53,274
Exploration and production		**47,045**		45,099		35,966
Construction materials and contracting		**25,241**		36,693		20,168
Construction services		**57,474**		9,930		6,545
Other		**7,832**		8,067		8,486
Intersegment eliminations		**(186,964)**		(146,488)		(124,439)
Total intersegment operating revenues	**$**	**—**	$	—	$	—
Depreciation, depletion and amortization:						
Electric	**$**	**35,008**	$	32,789	$	32,509
Natural gas distribution		**54,700**		50,031		45,731
Pipeline and energy services		**30,645**		29,119		27,684
Exploration and production		**198,199**		186,458		160,681
Construction materials and contracting		**68,557**		74,470		79,527
Construction services		**12,874**		11,939		11,063
Other		**2,196**		2,050		2,010
Intersegment eliminations		**(811)**		—		—
Total depreciation, depletion and amortization	**$**	**401,368**	$	386,856	$	359,205

	2014	2013	2012
		(In thousands)	
Interest expense:			
Electric	**$ 15,595**	$ 12,590	$ 12,421
Natural gas distribution	**27,217**	25,123	28,726
Pipeline and energy services	**10,048**	10,330	7,742
Exploration and production	**13,834**	14,315	9,018
Construction materials and contracting	**16,368**	17,394	15,211
Construction services	**4,176**	4,306	4,435
Other	**15**	15	13
Intersegment eliminations	**(237)**	(156)	(867)
Total interest expense	**$ 87,016**	$ 83,917	$ 76,699
Income taxes:			
Electric	**$ 12,442**	$ 9,683	$ 8,975
Natural gas distribution	**11,350**	16,633	12,005
Pipeline and energy services	**9,699**	3,390	15,291
Exploration and production	**47,739**	53,197	(108,264)
Construction materials and contracting	**18,586**	24,765	14,099
Construction services	**24,753**	29,504	24,128
Other	**(1,119)**	2,433	2,620
Intersegment eliminations	**(3,481)**	(2,869)	—
Total income taxes	**$ 119,969**	$ 136,736	$ (31,146)
Earnings (loss) on common stock:			
Electric	**$ 36,731**	$ 34,837	$ 30,634
Natural gas distribution	**30,484**	37,656	29,409
Pipeline and energy services	**22,628**	7,629	26,588
Exploration and production	**96,733**	94,450	(177,283)
Construction materials and contracting	**51,510**	50,946	32,420
Construction services	**54,432**	52,213	38,429
Other	**7,461**	5,136	4,797
Intersegment eliminations	**(5,608)**	(4,307)	—
Earnings (loss) on common stock before income (loss) from discontinued operations	**294,371**	278,560	(15,006)
Income (loss) from discontinued operations, net of tax*	**3,177**	(312)	13,567
Total earnings (loss) on common stock	**$ 297,548**	$ 278,248	$ (1,439)
Capital expenditures:			
Electric	**$ 185,121**	$ 168,557	$ 112,035
Natural gas distribution	**120,613**	101,279	130,178
Pipeline and energy services	**177,409**	127,092	133,787
Exploration and production	**600,572**	391,315	554,528
Construction materials and contracting	**37,896**	34,607	45,083
Construction services	**26,942**	15,102	14,835
Other	**2,131**	2,249	791
Net proceeds from sale or disposition of property and other	**(306,994)**	(112,131)	(57,460)
Total net capital expenditures	**$ 843,690**	$ 728,070	$ 933,777
Assets:			
Electric**	**$ 1,030,611**	$ 884,283	$ 760,324
Natural gas distribution**	**1,931,908**	1,786,068	1,703,459
Pipeline and energy services	**1,081,902**	798,701	622,470
Exploration and production	**1,738,064**	1,616,131	1,539,017
Construction materials and contracting	**1,272,231**	1,305,808	1,371,252
Construction services	**454,602**	450,614	429,547
Other***	**300,660**	219,727	256,422
Total assets	**$ 7,809,978**	$ 7,061,332	$ 6,682,491

	2014	2013	2012
		(In thousands)	
Property, plant and equipment:			
Electric**	**$ 1,457,101**	$ 1,315,822	$ 1,150,584
Natural gas distribution**	**1,904,759**	1,776,901	1,689,950
Pipeline and energy services	**1,220,233**	962,172	816,533
Exploration and production	**3,402,879**	3,060,848	2,764,560
Construction materials and contracting	**1,529,942**	1,510,355	1,504,981
Construction services	**144,395**	134,948	130,624
Other	**50,937**	49,997	50,519
Eliminations	**(17,075)**	(7,177)	—
Less accumulated depreciation, depletion and amortization	**4,166,407**	3,872,487	3,608,912
Net property, plant and equipment	**$ 5,526,764**	$ 4,931,379	$ 4,498,839

* Reflected in the Other category.

** 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).

Note: The results reflect $391.8 million ($246.8 million after tax) of noncash write-downs of oil and natural gas properties in 2012.

Excluding the impairments of the coalbed natural gas gathering assets of $9.0 million (after tax) and $1.7 million (after tax) in 2013 and 2012, respectively, and the reversal of the charge related to natural gas gathering operations litigation of $1.5 million (after tax) and $15.0 million (after tax) in 2013 and 2012, respectively, as discussed in Notes 1 and 19 , respectively, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from exploration and production, construction materials and contracting, construction services and other are all from nonregulated operations.

Capital expenditures for 2014 , 2013 and 2012 include noncash capital expenditure-related accounts payable and exclude capital expenditures of the noncontrolling interest related to Dakota Prairie Refinery. The net transactions were $(61.2) million in 2014 , $(56.8) million in 2013 and $33.7 million in 2012 .

Note 16 - 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.

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. In 2010, all benefit and service accruals for nonunion and certain union plans were frozen. In 2011 and 2012, all benefit and service accruals for certain additional union employees were 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.

Changes in benefit obligation and plan assets for the years ended December 31, 2014 and 2013 , and amounts recognized in the Consolidated Balance Sheets at December 31, 2014 and 2013 , were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	**2014**	2013
		(In thousands)		
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 402,772**	$ 459,111	**$ 81,726**	$ 103,358
Service cost	**129**	155	**1,518**	1,675
Interest cost	**17,682**	16,249	**3,521**	3,215
Plan participants' contributions	**—**	—	**1,399**	1,472
Actuarial (gain) loss	**80,520**	(44,551)	**18,024**	(20,985)
Benefits paid	**(25,766)**	(28,192)	**(7,176)**	(7,009)
Benefit obligation at end of year	**475,337**	402,772	**99,012**	81,726
Change in net plan assets:				
Fair value of plan assets at beginning of year	**334,844**	309,184	**84,543**	74,361
Actual gain on plan assets	**24,500**	35,539	**7,527**	13,819
Employer contribution	**20,785**	18,313	**1,293**	1,900
Plan participants' contributions	**—**	—	**1,399**	1,472
Benefits paid	**(25,766)**	(28,192)	**(7,176)**	(7,009)
Fair value of net plan assets at end of year	**354,363**	334,844	**87,586**	84,543
Funded status - (under) over	**$ (120,974)**	$ (67,928)	**$ (11,426)**	$ 2,817
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ —**	$ —	**$ 4,345**	$ 9,679
Other accrued liabilities (current)	**—**	—	**(322)**	(381)
Other liabilities (noncurrent)	**(120,974)**	(67,928)	**(15,449)**	(6,481)
Net amount recognized	**$ (120,974)**	$ (67,928)	**$ (11,426)**	$ 2,817
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 207,430**	$ 135,061	**$ 25,779**	$ 11,314
Prior service cost (credit)	**294**	365	**(15,744)**	(17,137)
Total	**$ 207,724**	$ 135,426	**$ 10,035**	$ (5,823)

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 6 .

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 on a straight-line basis over the expected average remaining service lives of active participants for non-frozen plans and 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. Unrecognized postretirement net transition obligation was amortized over a 20-year period ending 2012.

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:

	2014	2013
	(In thousands)	
Projected benefit obligation	**$ 475,337**	$ 402,772
Accumulated benefit obligation	**$ 475,337**	$ 402,772
Fair value of plan assets	**$ 354,363**	$ 334,844

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

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	**2014**	2013	2012
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	**$ 129**	$ 155	$ 1,078	**$ 1,518**	$ 1,675	$ 1,747
Interest cost	**17,682**	16,249	17,598	**3,521**	3,215	4,166
Expected return on assets	**(21,218)**	(19,917)	(23,536)	**(4,617)**	(4,343)	(4,890)
Amortization of prior service cost (credit)	**71**	71	(46)	**(1,393)**	(1,457)	(1,438)
Recognized net actuarial loss	**4,869**	7,173	7,070	**649**	1,814	2,134
Curtailment gain	**—**	—	(1,023)	**—**	—	—
Amortization of net transition obligation	**—**	—	—	**—**	—	2,128
Net periodic benefit cost (credit), including amount capitalized	**1,533**	3,731	1,141	**(322)**	904	3,847
Less amount capitalized	**388**	727	937	**(21)**	164	910
Net periodic benefit cost (credit)	**1,145**	3,004	204	**(301)**	740	2,937
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**77,238**	(60,173)	19,982	**15,114**	(30,461)	1,863
Prior service credit	**—**	—	—	**—**	—	(11,418)
Amortization of actuarial loss	**(4,869)**	(7,173)	(7,070)	**(649)**	(1,814)	(2,134)
Amortization of prior service (cost) credit	**(71)**	(71)	1,069	**1,393**	1,457	1,438
Amortization of net transition obligation	**—**	—	—	**—**	—	(2,128)
Total recognized in accumulated other comprehensive (income) loss	**72,298**	(67,417)	13,981	**15,858**	(30,818)	(12,379)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss	**$ 73,443**	$ (64,413)	$ 14,185	**$ 15,557**	$ (30,078)	$ (9,442)

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are $7.1 million and $71,000 , respectively. 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 2015 are $1.8 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	
	2014	2013	**2014**	2013
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%

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

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	**2014**	2013
Discount rate	**4.53%**	3.65%	**4.48%**	3.67%
Expected return on plan assets	**7.00%**	7.00%	**6.00%**	6.00%
Rate of compensation increase	**N/A**	N/A	**3.00%**	4.00%

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, 2014, 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 65 percent to

75 percent equity securities and 25 percent to 35 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.

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

	2014	2013
Health care trend rate assumed for next year	**4.0% – 7.0%**	6.0% – 7.0%
Health care cost trend rate - ultimate	**5.0% – 6.0%**	5.0% – 6.0%
Year in which ultimate trend rate achieved	**2017**	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, 2014 :

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 247	$ (207)
Effect on postretirement benefit obligation	$ 4,489	$ (3,832)

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.

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, 2014 and 2013 , 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, 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.

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 9,406	$ —	$ 9,406
Equity securities:				
U.S. companies	62,599	—	—	62,599
International companies	39,437	—	—	39,437
Collective and mutual funds*	116,265	42,483	—	158,748
Corporate bonds	—	42,721	—	42,721
Municipal bonds	—	7,561	—	7,561
U.S. Government securities	7,487	4,335	—	11,822
Total assets measured at fair value	$ 225,788	$ 106,506	$ —	$ 332,294

* Collective and mutual funds invest approximately 11 percent in common stock of mid-cap U.S. companies, 19 percent in common stock of large-cap U.S. companies, 12 percent in U.S. Government securities, 27 percent in corporate bonds, 13 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 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, 2014 and 2013 , 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, 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.

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,142	$ —	$ 2,142
Equity securities:				
U.S. companies	2,802	—	—	2,802
International companies	221	—	—	221
Insurance contract*	—	79,374	—	79,374
Total assets measured at fair value	$ 3,023	$ 81,516	$ —	$ 84,539

* The insurance contract invests approximately 55 percent in common stock of large-cap U.S. companies, 12 percent in U.S. Government securities, 8 percent in mortgage-backed securities, 8 percent in common stock of mid-cap U.S. companies, 9 percent in corporate bonds and 8 percent in other investments.

The Company expects to contribute approximately $3.9 million to its defined benefit pension plans and approximately $400,000 to its postretirement benefit plans in 2015 .

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)	
2015	$ 23,769	$ 5,162	$ 218
2016	24,025	5,186	213
2017	24,621	5,262	207
2018	25,064	5,329	200
2019	25,498	5,344	193
2020 - 2024	133,935	26,714	836

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. The Company's net periodic benefit cost for these plans was $6.6 million , $7.3 million and $8.1 million in 2014 , 2013 and 2012 , respectively. The total projected benefit obligation for these plans was $115.6 million and $106.9 million at December 31, 2014 and 2013 , respectively. The accumulated benefit obligation for these plans was $108.2 million and $99.7 million at December 31, 2014 and 2013 , respectively. A weighted average discount rate of 3.51 percent and 4.32 percent at December 31, 2014 and 2013 , respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent at December 31, 2014 and 2013 , were used to determine benefit obligations. A discount rate of 4.32 percent and 3.44 percent at December 31, 2014 and 2013 , respectively, and a rate of compensation increase of 4.00 percent and 3.00 percent at December 31, 2014 and 2013 , were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $6.6 million in 2015 ; $6.5 million in 2016 ; $6.7 million in 2017 ; $7.1 million in 2018 ; $7.3 million in 2019 and $37.9 million for the years 2020 through 2024.

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

The Company had investments of $101.4 million and $98.1 million at December 31, 2014 and 2013 , respectively, consisting of equity securities of $54.9 million and $53.5 million , respectively, life insurance carried on plan participants (payable upon the employee's death) of $32.8 million and $31.4 million , respectively, and other investments of $13.7 million and $13.2 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 $34.4 million in 2014 , $33.2 million in 2013 and $29.3 million in 2012 .

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 2014 and 2013 is for the plan's year-end at December 31, 2013 , and December 31, 2012 , 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.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2014	2013	FIP/RP Status Pending/Implemented	Contributions 2014	2013	2012	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green as of 12/31/2014	Green as of 12/31/2013	No	**$ 9,061**	$ 6,358	$ 5,171	No	12/31/2014*
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2014	Yellow as of 4/30/2013	Implemented	**777**	1,041	2,771	No	4/23/2017
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2014	Red as of 6/30/2013	Implemented	**1,392**	1,284	1,093	No	11/29/2015
IBEW Local No. 246 Pension Plan	34-6582842-001	Yellow as of 5/31/2014	Yellow as of 5/31/2013	Implemented	**694**	1,848	1	No	10/31/2017
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2014	Red as of 2/28/2013	Implemented	**1,110**	1,489	564	No	8/31/2015
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2014	Yellow as of 5/31/2013	Implemented	**663**	921	567	No	6/30/2016
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**6,476**	5,883	5,603	No	11/30/2019
OE Pension Trust Fund	94-6090764-001	Red as of 12/31/2014	Yellow	Implemented	**1,445**	1,510	1,156	No	6/15/2015–6/30/2016
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming**	83-6011320-001	Red as of 12/31/2014	Red as of 12/31/2013	Implemented	**68**	76	91	No	10/31/2005*
Operating Engineers Pension Trust	95-6032478-001	Red as of 6/30/2014	Red as of 6/30/2013	Implemented	**612**	493	761	No	7/1/2016
Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Red as of 12/31/2014	Red as of 12/31/2013	Implemented	**676**	512	467	No	6/30/2015
Southwest Marine Pension Trust	95-6123404-001	Red as of 12/31/2014	Red as of 12/31/2013	Implemented	**31**	42	76	No	1/31/2014*–1/31/2019
Other funds					**19,812**	17,803	16,458		
Total contributions					**$ 42,817**	$ 39,260	$ 34,779		

* 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	2013 and 2012
IBEW Local 38 Pension Plan	2012
IBEW Local No. 82 Pension Plan	2013 and 2012
Local Union No. 124 IBEW Pension Trust Fund	2013 and 2012
Local Union 212 IBEW Pension Trust Fund	2013 and 2012
IBEW Local Union No. 357 Pension Plan A	2013 and 2012
IBEW Local 648 Pension Plan	2013 and 2012
Idaho Plumbers and Pipefitters Pension Plan	2012
Minnesota Teamsters Construction Division Pension Fund	2013 and 2012
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming*	2013 and 2012
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	2013 and 2012

* 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, which the Company currently estimates at approximately $14 million (approximately $8.4 million after tax). 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 $34.6 million , $37.1 million and $31.4 million for the years ended December 31, 2014 , 2013 and 2012 , respectively.

Amounts contributed in 2014 , 2013 and 2012 to defined contribution multiemployer plans were $22.0 million , $20.6 million and $18.7 million , respectively.

Note 17 - 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:

	2014	2013
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 64,283**	$ 63,890
Less accumulated depreciation	**43,043**	41,323
	$ 21,240	$ 22,567
Coyote Station:		
Utility plant in service	**$ 138,810**	$ 138,261
Less accumulated depreciation	**94,443**	89,528
	$ 44,367	$ 48,733
Wygen III:		
Utility plant in service	**$ 65,597**	$ 64,332
Less accumulated depreciation	**5,928**	4,639
	$ 59,669	$ 59,693

Note 18 - Regulatory Matters and Revenues Subject to Refund

On August 11, 2014, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total increase of approximately $3.0 million annually or approximately 3.6 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, depreciation and taxes associated with the increased investment as well as an increase in Montana-Dakota's operation and maintenance expenses. On February 3, 2015, the MTPSC approved an interim increase of $2.0 million or approximately 2.3 percent, subject to refund, to be effective with service rendered on and after February 6, 2015. The MTPSC has scheduled a hearing for this matter on March 25, 2015.

On October 3, 2014, Montana-Dakota filed an application with the WYPSC for a natural gas rate increase. Montana-Dakota requested a total increase of approximately $788,000 annually or approximately 4.1 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. The WYPSC has scheduled a hearing for this matter on May 19, 2015.

On November 14, 2014, Montana-Dakota filed an application with the NDPSC for approval to implement the rate adjustment associated with the electric generation resource recovery rider approved by the NDPSC on August 20, 2014. On January 7, 2015, the NDPSC approved the rate adjustments of $5.3 million annually to be effective with service rendered on and after January 9, 2015.

On December 22, 2014, Montana-Dakota filed an application for advance determination of prudence and a certificate of public convenience and necessity with the NDPSC for the Thunder Spirit Wind project. This project will provide energy, capacity and renewable energy credits to Montana-Dakota's electric customers in North Dakota, Montana and South Dakota.

On February 6, 2015, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase. Montana-Dakota requested a total increase of approximately $4.3 million annually or approximately 3.4 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, depreciation and taxes associated with the increased investment as well as an increase in Montana-Dakota's operation and maintenance expenses. Montana-Dakota requested an interim increase of $4.3 million or 3.4 percent, subject to refund. This matter is pending before the NDPSC.

Note 19 - 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 $27.6 million and $29.5 million for contingencies, including litigation, production taxes, royalty claims and environmental matters at December 31, 2014 and 2013 , respectively, which include amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

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

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

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel WBI Energy Midstream to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of WBI Energy Midstream's pipeline gathering systems in Montana. WBI Energy Midstream resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered WBI Energy Midstream into arbitration. In October 2010, the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million . As a result, WBI Energy Midstream, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010. On April 20, 2011, the Colorado State District Court confirmed the arbitration award as a court judgment. WBI Energy Midstream filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals. The Colorado Court of Appeals issued a decision on May 24, 2012, reversing the Colorado State District Court order compelling arbitration, vacating the final award and remanding the case to the Colorado State District Court to determine SourceGas's claims and WBI Energy Midstream's counterclaims. As a result of the Colorado Court of Appeals decision, in the second quarter of 2012, WBI Energy Midstream changed its estimated loss related to this matter. This resulted in a reduction of expense of $24.1 million ($15.0 million after tax), which was largely reflected in operation and maintenance expense on the Consolidated Statements of Income. On August 2, 2012, SourceGas filed a petition for writ of certiorari with the Colorado Supreme Court for review of the Colorado Court of Appeals decision which was denied on July 22, 2013. On remand of the matter to the Colorado State District Court, SourceGas may assert claims similar to those asserted in the arbitration proceeding.

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

On May 15, 2013, Austin Holdings, LLC filed an action against Fidelity in Wyoming State District Court alleging Fidelity violated the Wyoming Royalty Payment Act and implied lease covenants by deducting production costs from and by failing to properly report and pay royalties for coalbed methane gas production in Wyoming. The plaintiff, in addition to declaratory and injunctive relief, seeks class certification for similarly situated persons and an unspecified amount of monetary damages on behalf of the class for unpaid royalties, interest, reporting violations and attorney fees. The Company reached a settlement of the matter, subject to court approval, for an amount that is not material.

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 investigative costs to the extent Knife River - Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River - Northwest has agreed to participate in the alternative dispute resolution process.

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

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

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million . The Oregon DEQ 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 and December 1, 2014.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million . Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.5 million for the remedial investigation, feasibility study and remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

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

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers. The accruals related to these matters are reflected in regulatory assets. For more information, see Note 6 .

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, 2014 , were $48.1 million in 2015 , $43.5 million in 2016 , $34.3 million in 2017 , $28.1 million in 2018 , $19.7 million in 2019 and $78.7 million thereafter. Rent expense was $53.7 million , $48.1 million and $42.9 million for the years ended December 31, 2014 , 2013 and 2012 , respectively.

Purchase commitments

The Company has entered into various commitments, largely construction, natural gas and coal supply, purchased power, natural gas transportation and storage, service, shipping and construction materials supply contracts, some of which are subject to variability in volume and price, and a purchase agreement of electric wind generation. These commitments range from one to 46 years . The commitments under these contracts as of December 31, 2014 , were $694.7 million in 2015 , $304.6 million in 2016 , $161.0 million in 2017 , $91.0 million in 2018 , $86.4 million in 2019 and $910.6 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, 2014 , 2013 and 2012 , were $925.2 million , $861.8 million and $718.4 million , respectively.

Guarantees

In connection with the sale of the Brazilian Transmission Lines, as discussed in Note 4 , Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

WBI Holdings has guaranteed certain of Fidelity's oil and natural gas swap agreement obligations. There is no fixed maximum amount guaranteed in relation to the oil and natural gas swap agreements as the amount of the obligation is dependent upon oil and natural gas commodity prices. The amount of derivative activity entered into by the subsidiary is limited by corporate policy. The guarantees of the oil and natural gas swap agreements at December 31, 2014 , expire in the year 2015; however, Fidelity may continue to enter into additional derivative instruments and, as a result, WBI Holdings from time to time may issue additional guarantees on these derivative instruments. There were no amounts outstanding by Fidelity at December 31, 2014 . In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At December 31, 2014 , the fixed maximum amounts guaranteed under these agreements aggregated $86.7 million . The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $66.9 million in 2015 ; $700,000 in 2016 ; $600,000 in 2017 ; $500,000 in 2018 ; $500,000 in 2019 ; $13.5 million , which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million , which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $200,000 and was reflected on the Consolidated Balance Sheet at December 31, 2014 . In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2014 , the fixed maximum amounts guaranteed under these letters of credit, aggregated $36.4 million and are scheduled to expire in 2015 . There were no amounts outstanding under the above letters of credit at December 31, 2014 .

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

WBI Holdings has an outstanding guarantee to WBI Energy Transmission. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2014 , the fixed maximum amount guaranteed under this agreement was $4.0 million and is scheduled to expire in 2016. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.1 million . The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2014 , because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2014 .

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2014 , approximately $423.5 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 expected to be shared equally between WBI Energy and Calumet. The total project cost is currently estimated at more than $400 million . 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.

On December 1, 2014, Dakota Prairie Refining entered into a $50 million revolving credit agreement with an expiration date of December 1, 2015. Pursuant to the revolving credit agreement, WBI Holdings has guaranteed 50 percent of the credit agreement and Calumet has 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.

Construction of Dakota Prairie Refinery began in early 2013 and the plant is not yet operational. Therefore, the results of operations of Dakota Prairie Refining did not have a material effect on the Company's Consolidated Statements of Income. The assets of Dakota Prairie Refining shall be used solely for the benefit of Dakota Prairie Refining. The total assets and liabilities of Dakota Prairie Refining reflected on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2014	2013
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 21,376**	$ 4,774
Accounts receivable	**2,759**	—
Inventories	**5,311**	—
Other current assets	**4,019**	26
Total current assets	**33,465**	4,800
Net property, plant and equipment	**398,984**	172,073
Deferred charges and other assets:		
Other	**3,400**	—
Total deferred charges and other assets	**3,400**	—
Total assets	**$ 435,849**	$ 176,873
Liabilities		
Current liabilities:		
Long-term debt due within one year	**$ 3,000**	$ 3,000
Accounts payable	**55,089**	8,904
Taxes payable	**648**	5
Accrued compensation	**727**	26
Other accrued liabilities	**899**	461
Total current liabilities	**60,363**	12,396
Long-term debt	**69,000**	72,000
Total liabilities	**$ 129,363**	$ 84,396

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

The new coal supply agreement creates a variable interest in Coyote Creek due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so 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, 2014 , Coyote Creek was not yet operational. The assets and liabilities of Coyote Creek and exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage, at December 31, 2014 , was $15.8 million .

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2014 and 2013 :

		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
				(In thousands, except per share amounts)				
2014								
Operating revenues	$	**1,042,853**	$	**1,094,046**	$	**1,370,455**	$	**1,163,204**
Operating expenses		**939,949**		**995,112**		**1,193,690**		**1,053,582**
Operating income		**102,904**		**98,934**		**176,765**		**109,622**
Income from continuing operations		**56,184**		**52,780**		**102,118**		**80,079**
Income (loss) from discontinued operations, net of tax		**(45)**		**547**		**3**		**2,672**
Net income attributable to the Company		**56,662**		**54,106**		**103,209**		**84,256**
Earnings per common share - basic:								
Earnings before discontinued operations		**.30**		**.28**		**.53**		**.42**
Discontinued operations, net of tax		**—**		**—**		**—**		**.01**
Earnings per common share - basic		**.30**		**.28**		**.53**		**.43**
Earnings per common share - diluted:								
Earnings before discontinued operations		**.30**		**.28**		**.53**		**.42**
Discontinued operations, net of tax		**—**		**—**		**—**		**.01**
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**
2013								
Operating revenues	$	931,604	$	1,060,595	$	1,285,782	$	1,184,423
Operating expenses		827,073		969,217		1,135,909		1,037,306
Operating income		104,531		91,378		149,873		147,117
Income from continuing operations		56,592		46,392		84,550		91,348
Loss from discontinued operations, net of tax		(77)		(59)		(118)		(58)
Net income attributable to the Company		56,515		46,512		84,456		91,450
Earnings per common share - basic:								
Earnings before discontinued operations		.30		.25		.45		.48
Discontinued operations, net of tax		—		—		—		—
Earnings per common share - basic		.30		.25		.45		.48
Earnings per common share - diluted:								
Earnings before discontinued operations		.30		.24		.44		.48
Discontinued operations, net of tax		—		—		—		—
Earnings per common share - diluted		.30		.24		.44		.48
Weighted average common shares outstanding:								
Basic		188,831		188,831		188,831		188,929
Diluted		189,222		189,463		189,638		189,766

Notes:

- First quarter 2014 reflects an unrealized loss on commodity derivatives of $4.3 million (after tax). First quarter 2013 reflects an unrealized loss on commodity derivatives of $3.7 million (after tax).
- Second quarter 2014 reflects an unrealized loss on commodity derivatives of $3.3 million (after tax). Second quarter 2013 reflects an impairment of coalbed natural gas gathering assets of $9.0 million (after tax) and an unrealized gain on commodity derivatives of $8.2 million (after tax). For more information, see Note 1 .
- Third quarter 2014 reflects an unrealized gain on commodity derivatives of $18.1 million (after tax). Third quarter 2013 reflects an unrealized loss on commodity derivatives of $7.9 million (after tax).
- Fourth quarter 2014 reflects a MEPP withdrawal liability of $8.4 million (after tax) and an unrealized gain on commodity derivatives of $4.1 million (after tax). Fourth quarter 2013 reflects a net benefit of $1.5 million (after tax) related to natural gas gathering operations litigation and an unrealized loss on commodity derivatives of $500,000 (after tax). For more information, see Notes 16 and 19 .

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)

Fidelity is involved in the development and production of oil and natural gas resources. Fidelity shares revenues and expenses from the development of specified properties in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States 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:

	2014	2013	2012
		(In thousands)	
Subject to amortization	**$ 3,205,036**	$ 2,893,010	$ 2,531,562
Not subject to amortization	**132,141**	124,869	191,794
Total capitalized costs	**3,337,177**	3,017,879	2,723,356
Less accumulated depreciation, depletion and amortization	**1,752,566**	1,562,116	1,383,386
Net capitalized costs	**$ 1,584,611**	$ 1,455,763	$ 1,339,970

Note: Net capitalized costs reflect noncash write-downs of the Company's oil and natural gas properties, as discussed in Note 1 .

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

Years ended December 31,	2014 *	2013 *	2012 *
		(In thousands)	
Acquisitions:			
Proved properties	**$ 87,919**	$ 1,817	$ 839
Unproved properties	**138,683**	4,608	31,109
Exploration	**16,879**	26,975	235,906
Development	**331,400**	355,421	275,959
Total capital expenditures	**$ 574,881**	$ 388,821	$ 543,813

* 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, as discussed in Note 10 , of $(9.0) million , $(10.7) million and $(200,000) for the years ended December 31, 2014 , 2013 and 2012, respectively.

The preceding table excludes proceeds from the sales of oil and natural gas properties of $246.6 million , $83.6 million and $6.0 million for the years ended December 31, 2014, 2013 and 2012, respectively.

The following summary reflects income resulting from the Company's operations of oil and natural gas producing activities, excluding corporate overhead and financing costs:

Years ended December 31,	2014	2013	2012
		(In thousands)	
Revenues:			
Sales to affiliates	**$ 47,045**	$ 45,099	$ 35,966
Sales to external customers	**468,668**	497,018	379,647
Realized gain on commodity derivatives	**8,458**	173	33,628
Unrealized gain (loss) on commodity derivatives	**23,400**	(6,267)	(624)
Production costs	**146,793**	144,136	134,795
Depreciation, depletion and amortization*	**193,944**	182,352	157,078
Write-downs of oil and natural gas properties	**—**	—	391,800
Pretax income (loss)	**206,834**	209,535	(235,056)
Income tax expense (benefit)	**75,483**	75,836	(88,612)
Results of operations for producing activities	**$ 131,351**	$ 133,699	$ (146,444)

* Includes accretion of discount for asset retirement obligations of $3.5 million , $3.6 million and $3.3 million for the years ended December 31, 2014, 2013 and 2012, respectively, as discussed in Note 10 .

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, 2014 , 2013 and 2012 , 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. In addition, the Company engaged Ryder Scott, an independent third party, to audit its proved reserve quantity estimates.

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 Company's interests in oil, NGL and natural gas reserves are located in the United States and in and around the Gulf of Mexico.

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

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:

- Extension 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 changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2012, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	27,005	7,342	379,827	97,651
Production	(3,694)	(828)	(33,214)	(10,058)
Extensions and discoveries	9,874	1,817	18,386	14,756
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(39)	—	(2,307)	(423)
Revisions of previous estimates	307	(1,178)	(123,414)	(21,440)
Balance at end of year	33,453	7,153	239,278	80,486

Significant changes in proved reserves for the year ended December 31, 2012, include:

- Extensions and discoveries of 14.8 MMBOE, primarily due to drilling activity at the Company's Bakken, South Texas and Paradox properties
- Revisions of previous estimates of (21.4) MMBOE, largely the result of lower natural gas prices resulting in a reduction of PDP and PUD reserves principally in the Company's Coalbed, Baker, Bowdoin, East Texas and Green River Basin natural gas properties

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

	2014	2013	2012
Proved developed reserves:			
Oil (MBbls)	**30,130**	31,394	27,412
NGL (MBbls)	**4,217**	5,322	5,342
Natural Gas (MMcf)	**184,437**	176,546	218,259
Total (MBOE)	**65,086**	66,140	69,131
PUD reserves:			
Oil (MBbls)	**13,788**	9,625	6,041
NGL (MBbls)	**2,970**	1,280	1,811
Natural Gas (MMcf)	**60,574**	21,899	21,019
Total (MBOE)	**26,854**	14,555	11,355
Total proved reserves:			
Oil (MBbls)	**43,918**	41,019	33,453
NGL (MBbls)	**7,187**	6,602	7,153
Natural Gas (MMcf)	**245,011**	198,445	239,278
Total (MBOE)	**91,940**	80,695	80,486

As of December 31, 2014 , the Company had 26.9 MMBOE of PUD reserves, which is an increase of 12.3 MMBOE from December 31, 2013 . The increase relates to the Company adding 21.2 MMBOE of new PUD reserves and acquiring 3.9 MMBOE. This was partially offset by the Company converting 3.7 MMBOE, requiring $98.3 million of drilling and completion capital in 2014, divesting of 6.4 MMBOE, and negative PUD revisions of 2.7 MMBOE. At December 31, 2014 , the Company did not have any PUD locations that remained undeveloped for five years or more. Future development costs estimated to be spent in each of the next three years to develop PUD reserves at December 31, 2014 , are $141.8 million in 2015 , $157.4 million in 2016 and $120.9 million in 2017 . The future development costs are prepared using year-end costs and assuming continuation of existing economic and operating conditions and are not necessarily reflective of the Company's expectations. The timing of marketing the exploration and production business may also affect future development costs.

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	2012
		(In thousands)	
Future cash inflows	$ 5,185,500	$ 4,507,000	$ 3,696,200
Future production costs	1,856,900	1,734,800	1,536,500
Future development costs	570,200	403,000	301,600
Future net cash flows before income taxes	2,758,400	2,369,200	1,858,100
Future income tax expense	686,100	545,200	304,900
Future net cash flows	2,072,300	1,824,000	1,553,200
10% annual discount for estimated timing of cash flows	997,400	810,000	669,800
Discounted future net cash flows relating to proved oil, NGL and natural gas reserves	$ 1,074,900	$ 1,014,000	$ 883,400

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

	2014	2013	2012
		(In thousands)	
Beginning of year	$ 1,014,000	$ 883,400	$ 978,800
Net revenues from production	(368,900)	(398,000)	(280,800)
Net change in sales prices and production costs related to future production	86,300	162,200	(406,300)
Extensions and discoveries, net of future production-related costs	231,900	366,500	355,300
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)	(2,600)
Changes in estimated future development costs	65,100	6,700	37,600
Development costs incurred during the current year	104,600	141,500	77,700
Accretion of discount	109,400	94,600	121,400
Net change in income taxes	(33,400)	(141,400)	110,000
Revisions of previous estimates	(16,300)	(55,800)	(100,700)
Other	(2,300)	(7,900)	(7,000)
Net change	60,900	130,600	(95,400)
End of year	$ 1,074,900	$ 1,014,000	$ 883,400

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. In addition, future realization of oil, NGL and natural gas prices over the remaining reserve lives may vary significantly from SEC Defined Prices.

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
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
Brazilian Transmission Lines	Company's investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and portions of the ownership interest in ECTE were sold in the first quarter of 2015, the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010)
Btu	British thermal unit
California Superior Court	Superior Court of the State of California, County of Los Angeles (South District - Long Beach)
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
Connolly-Pacific	Connolly-Pacific Co., an indirect wholly owned subsidiary of Knife River
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant being built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (2.5 percent ownership interest at December 31, 2014, 2.5, 2.5, 2.5 and 14.99 percent ownership interests were sold in the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010, respectively, with the remaining 2.5 percent ownership interest sold in January 2015)
EIN	Employer Identification Number
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
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
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
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
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MEPP	Multiemployer pension plan
MMBOE	Millions of BOE
MMBtu	Million Btu
MMcf	Million cubic feet
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
NGL	Natural gas liquids
NYMEX	New York Mercantile Exchange
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PDP	Proved developed producing
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
PRP	Potentially Responsible Party
PUD	Proved undeveloped
ROD	Record of Decision
RP	Rehabilitation plan
Ryder Scott	Ryder Scott Company, L.P.
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
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

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, 2014 , 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.

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is included in the last sentence of the third 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

Equity Compensation Plan Information

The following table includes information as of December 31, 2014 , with respect to the Company's equity compensation plans:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights		(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	
Equity compensation plans approved by stockholders (1)	688,455	(2)	$ 28.16	4,953,800	(3)(4)
Equity compensation plans not approved by stockholders	N/A		N/A	N/A	

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan, the Long-Term Performance-Based Incentive Plan and the Non-Employee Director Stock Compensation Plan.

(2) Consists of performance shares.

(3) 357,757 shares remain available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan in connection with grants of restricted stock, performance units, performance shares or other equity-based awards. 4,463,373 shares under the Long-Term Performance-Based Incentive Plan remain available for future issuance in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.

(4) This amount also includes 132,670 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors are awarded shares equal in value to $110,000 annually. A non-employee director may acquire additional shares under the plan in lieu of receiving the cash portion of the director's retainer or fees.

The remaining information required by this item is included under the caption "Security Ownership" in the Proxy Statement, 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 2. Ratification of Independent Registered Public Accounting Firm - Accounting and Auditing Matters" in the Proxy Statement, which information is incorporated herein by reference.

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

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Income and Comprehensive Income

Years ended December 31,	**2014**	2013	2012
		(In thousands)	
Operating revenues	**$ 628,578**	$ 549,239	$ 472,302
Operating expenses	**547,820**	473,917	405,095
Operating income	**80,758**	75,322	67,207
Other income	**5,271**	3,709	3,925
Interest expense	**21,055**	17,386	17,297
Income before income taxes	**64,974**	61,645	53,835
Income taxes	**16,819**	13,520	11,798
Equity in earnings (loss) of subsidiaries	**250,078**	230,808	(42,791)
Net income (loss) attributable to the Company	**298,233**	278,933	(754)
Dividends declared on preferred stocks	**685**	685	685
Earnings (loss) on common stock	**$ 297,548**	$ 278,248	$ (1,439)

Comprehensive income (loss)	**$ 294,335**	$ 289,449	$ (2,474)

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

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Balance Sheets

December 31,	2014	2013
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 6,120	$ 5,051
Receivables, net	91,493	88,529
Accounts receivable from subsidiaries	32,691	31,372
Inventories	33,584	29,312
Deferred income taxes	547	3,196
Prepayments and other current assets	70,852	14,231
Total current assets	235,287	171,691
Investments	64,446	60,687
Investment in subsidiaries	2,590,283	2,380,829
Property, plant and equipment	1,984,956	1,785,861
Less accumulated depreciation, depletion and amortization	660,026	660,693
Net property, plant and equipment	1,324,930	1,125,168
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	163,408	121,253
Total deferred charges and other assets	168,220	126,065
Total assets	$ 4,383,166	$ 3,864,440
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ 109	$ 109
Accounts payable	48,088	45,282
Accounts payable to subsidiaries	30,863	4,839
Taxes payable	10,583	12,337
Dividends payable	35,607	33,737
Accrued compensation	11,227	16,076
Other accrued liabilities	36,488	28,042
Total current liabilities	172,965	140,422
Long-term debt	508,164	434,598
Deferred credits and other liabilities:		
Deferred income taxes	251,067	205,639
Other liabilities	316,929	260,617
Total deferred credits and other liabilities	567,996	466,256
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	15,000	15,000
Common stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 194,754,812 shares in 2014 and 189,868,780 shares in 2013	194,755	189,869
Other paid-in capital	1,207,188	1,056,996
Retained earnings	1,762,827	1,603,130
Accumulated other comprehensive loss	(42,103)	(38,205)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	3,119,041	2,808,164
Total stockholders' equity	3,134,041	2,823,164
Total liabilities and stockholders' equity	$ 4,383,166	$ 3,864,440

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

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Cash Flows

Years ended December 31,	2014	2013	2012
		(In thousands)	
Net cash provided by operating activities	$ 208,208	$ 188,259	$ 225,968
Investing activities:			
Capital expenditures	(223,251)	(211,013)	(150,337)
Net proceeds from sale or disposition of property and other	1,552	20,624	1,120
Investments in and advances to subsidiaries	(134,451)	(1,016)	(1,387)
Advances from subsidiaries	64,500	10,000	5,000
Investments	(794)	613	12
Net cash used in investing activities	(292,444)	(180,792)	(145,592)
Financing activities:			
Issuance of long-term debt	148,959	77,924	76,000
Repayment of long-term debt	(76,432)	(85)	(21)
Proceeds from issuance of common stock	150,060	14,554	88
Dividends paid	(136,712)	(98,405)	(159,768)
Excess tax benefit on stock-based compensation	3,326	—	21
Tax withholding on stock-based compensation	(3,896)	—	—
Net cash provided by (used in) financing activities	85,305	(6,012)	(83,680)
Increase (decrease) in cash and cash equivalents	1,069	1,455	(3,304)
Cash and cash equivalents - beginning of year	5,051	3,596	6,900
Cash and cash equivalents - end of year	$ 6,120	$ 5,051	$ 3,596

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

Notes to Condensed Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, which is comprised of MDU Resources Group, Inc. (the Company) and Montana-Dakota and Great Plains, public utility divisions of the Company. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income (loss) from subsidiaries is reported as equity in earnings (loss) of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. In Schedule I, amounts from discontinued operations have not been separately stated. These statements should be read in conjunction with the consolidated financial statements and notes thereto of MDU Resources Group, Inc.

Earnings (loss) per common share Please refer to the Consolidated Statements of Income of the registrant for earnings (loss) per common share. In addition, see Note 1 of Notes to Consolidated Financial Statements for information on the computation of earnings (loss) per common share.

Note 2 - Debt The Company has long-term debt obligations outstanding of $508.3 million at December 31, 2014 , with annual maturities of $100,000 in 2015 , $50.1 million in 2016 , $100,000 in 2017 , $100.0 million in 2018 , $77.5 million in 2019 and $280.5 million scheduled to mature in years after 2019 .

For more information on debt, see Note 9 of Notes to Consolidated Financial Statements.

Note 3 - Dividends The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $105.6 million , $77.6 million and $125.8 million for the years ended December 31, 2014 , 2013 and 2012 , respectively.

Part IV

MDU RESOURCES GROUP, INC.
Schedule II - Consolidated Valuation and Qualifying Accounts

For the years ended December 31, 2014, 2013 and 2012

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other *	Deductions **	Balance at End of Year
			(In thousands)		
Allowance for doubtful accounts:					
2014	**$ 10,085**	**$ 8,548**	**$ 1,335**	**$ 10,457**	**$ 9,511**
2013	10,818	5,725	1,395	7,853	10,085
2012	12,407	7,064	1,754	10,407	10,818

* Recoveries.
** Uncollectible accounts written off.

All other schedules are omitted because of the absence of the conditions under which they are required, or because the information required is included in the Company's Consolidated Financial Statements and Notes thereto.

3. Exhibits

3(a) Restated Certificate of Incorporation of MDU Resources Group, Inc., as amended, dated May 13, 2010, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*

3(b) Bylaws of MDU Resources Group, Inc., as amended and restated on August 14, 2014, filed as Exhibit 3.1 to Form 8-K dated August 14, 2014, filed on August 19, 2014, in File No. 1-3480*

4(a) Indenture, dated as of December 15, 2003, between MDU Resources Group, Inc. and The Bank of New York, as trustee, filed as Exhibit 4(f) to Form S-8 on January 21, 2004, in Registration No. 333-112035*

4(b) First Supplemental Indenture, dated as of November 17, 2009, between MDU Resources Group, Inc. and The Bank of New York Mellon, as trustee, filed as Exhibit 4(c) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

4(c) Centennial Energy Holdings, Inc. Amended and Restated Master Shelf Agreement, effective as of April 29, 2005, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America and certain investors described therein, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

4(d) Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(e) MDU Resources Group, Inc. Credit Agreement, dated May 26, 2011, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4(e) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

4(f) First Amendment to Credit Agreement, dated October 4, 2012, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4 to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

4(g) Second Amendment to Credit Agreement, dated May 8, 2014, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

4(h) Third Amended and Restated Credit Agreement, dated May 8, 2014, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

4(i) MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America and the holders of the notes thereunder, filed as Exhibit 4 to Form 8-K dated August 16, 2007, filed on August 16, 2007, in File No. 1-3480*

4(j) Amendment No. 1 to Master Shelf Agreement, dated October 1, 2008, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America, and the holders of the notes thereunder, filed as Exhibit 4(b) to Form 10-Q for the quarter ended September 30, 2008, filed on November 5, 2008, in File No. 1-3480*

4(k) Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 8-K dated August 12, 1992, in File No. 1-7196*

4(l) First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 10-Q for the quarter ended June 30, 1993, in File No. 1-7196*

4(m) Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*

4(n) Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*

+10(a) Supplemental Income Security Plan, as amended and restated November 12, 2009, filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(b) Director Compensation Policy, as amended May 15, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

+10(c) Deferred Compensation Plan for Directors, as amended May 15, 2008, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2008, filed on August 7, 2008, in File No. 1-3480*

+10(d) Non-Employee Director Stock Compensation Plan, as amended May 12, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*

+10(e) MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*

+10(f) Long-Term Performance-Based Incentive Plan, as amended November 17, 2011, filed as Exhibit 10(h) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(g) MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended March 4, 2013, and Rules and Regulations, as amended March 4, 2013, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2013, filed on May 7, 2013, in File No. 1-3480*

+10(h) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended November 14, 2012, filed as Exhibit 10.1 to Form 8-K dated November 14, 2012, filed on November 20, 2012, in File No. 1-3480*

+10(i) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 12, 2014, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*

+10(j) Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 12, 2014, filed as Exhibit 10.2 to Form 8-K dated February 12, 2014, filed on February 19, 2014, in File No. 1-3480*

+10(k) Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, filed as Exhibit 10.1 to Form 8-K dated May 15, 2014, filed on May 15, 2014, in File No. 1-3480*

+10(l) Form of Amendment No. 1 to Indemnification Agreement, filed as Exhibit 10.2 to Form 8-K dated May 15, 2014, filed on May 15, 2014, in File No. 1-3480*

+10(m) MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of January 9, 2015**

+10(n) Employment Letter for J. Kent Wells, dated March 9, 2011, filed as Exhibit 10(v) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(o) MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as adopted November 17, 2011, filed as Exhibit 10(x) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(p) MDU Resources Group, Inc. 401(k) Retirement Plan, as restated March 1, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*

+10(q) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 29, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2011, filed on May 5, 2011, in File No. 1-3480*

+10(r)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2011, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*
+10(s)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*
+10(t)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2011, filed as Exhibit 10(ac) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*
+10(u)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated May 24, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*

+10(v)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*
+10(w)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*
+10(x)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 19, 2012, filed as Exhibit 10(z) to Form 10-K for the year ended December 31, 2012, filed on February 28, 2013, in File No. 1-3480*
+10(y)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*
+10(z)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(c) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*
+10(aa)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 23, 2013, filed as Exhibit 10(d) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*
+10(ab)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 31, 2013, filed as Exhibit 10(aa) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*
+10(ac)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 13, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*
+10(ad)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 5, 2014, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*
+10(ae)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated July 7, 2014, filed as Exhibit 4.20 to Form S-8, filed on August 26, 2014, in Registration No. 333-198364*
+10(af)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 18, 2014, filed as Exhibit 4.21 to Form S-8, filed on August 26, 2014, in Registration No. 333-198364*
+10(ag)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 30, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2014, filed on November 7, 2014, in File No. 1-3480*
+10(ah)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated November 25, 2014**
+10(ai)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 11, 2014**
+10(aj)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 11, 2014**
+10(ak)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 30, 2014**
+10(al)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013, filed as Exhibit 10(ab) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*
+10(am)	Agreement with J. Kent Wells, dated January 22, 2015, filed as Exhibit 10 to Form 8-K dated January 20, 2015, filed on January 23, 2015, in File No. 1-3480*
10(an)	Purchase and Sale Agreement, dated February 10, 2014, dated effective October 1, 2013, between Fidelity Exploration & Production Company, Fidelity Oil Co. and Ballard Petroleum Holdings LLC, filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*
10(ao)	Purchase and Sale Agreement, dated February 10, 2014, dated effective October 1, 2013, between Fidelity Exploration & Production Company, Fidelity Oil Co. and Maurice W. Brown Oil & Gas, LLC, filed as Exhibit 10(d) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*
10(ap)	Purchase and Sale Agreement, dated July 17, 2014, between Fidelity Exploration & Production Company and Lime Rock Resources, III-A, L.P., filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2014, filed on November 7, 2014, in File No. 1-3480*

12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**
21	Subsidiaries of MDU Resources Group, Inc.**
23(a)	Consent of Independent Registered Public Accounting Firm**
23(b)	Consent of Ryder Scott Company, L.P.**
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**
95	Mine Safety Disclosures**
99(a)	Ryder Scott Company, L.P. report dated January 29, 2015**

99(b)	Equity Distribution Agreement entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 1 to Form 8-K dated May 20, 2013, filed on May 20, 2013, in File No. 1-3480*
99(c)	First Amendment to Equity Distribution Agreement, dated December 2, 2013, entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 99(c) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*
101	The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Equity, (v) the Consolidated Statements of Cash Flows, (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail, (vii) Schedule I - Condensed Financial Information of Registrant, tagged in summary and detail and (viii) Schedule II - Consolidated Valuation and Qualifying Accounts, tagged in summary and detail

* Incorporated herein by reference as indicated.

** Filed herewith.

\+ Management contract, compensatory plan or arrangement.

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

Part IV

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MDU Resources Group, Inc.

Date:	February 20, 2015	By:	/s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities and on the date indicated.

Signature	Title	Date
/s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)	Chief Executive Officer and Director	February 20, 2015
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 20, 2015
/s/ Nathan W. Ring Nathan W. Ring (Vice President, Controller and Chief Accounting Officer)	Chief Accounting Officer	February 20, 2015
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 20, 2015
/s/ Thomas Everist Thomas Everist	Director	February 20, 2015
/s/ Karen B. Fagg Karen B. Fagg	Director	February 20, 2015
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 20, 2015
/s/ A. Bart Holaday A. Bart Holaday	Director	February 20, 2015
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 20, 2015
/s/ William E. McCracken William E. McCracken	Director	February 20, 2015
/s/ Patricia L. Moss Patricia L. Moss	Director	February 20, 2015
/s/ J. Kent Wells J. Kent Wells	Director	February 20, 2015
/s/ John K. Wilson John K. Wilson	Director	February 20, 2015

INSTRUMENT OF AMENDMENT TO THE
MDU RESOURCES GROUP, INC.
401(k) RETIREMENT PLAN

The MDU Resources Group, Inc. 401(k) Retirement Plan, (as restated March 1, 2011) (the "Plan"), is hereby further amended as follows, effective as of January 1, 2008, unless otherwise indicated:

1. By replacing the definition of "Eligible Employee" with the following definition where such definition occurs in Article I of the Plan:

   <u>Eligible Employee</u> – An "Eligible Employee" means each regular full-time Employee or part-time Employee scheduled to work at least 1,000 hours a year who is at least 18 years of age and who is actively employed by the Employer, provided, however, that a part-time Employee scheduled to work less than 1,000 hours a year who completes more than 1,000 hours of service within a twelve-month period beginning on the Employee's employment date or in any subsequent Plan Year shall be an Eligible Employee. Notwithstanding the foregoing, an Employee of an Employer shall not be an Eligible Employee during any time when such Employee is 1) eligible to participate in a retirement plan which is a multi-employer plan as defined in Section 3(37) of ERISA to which the Employer contributes, 2) covered by a collectively bargained unit which has not bargained for the Plan for such Employee, 3) classified as a student or intern as defined by the payroll practices of the Employer, or 4) classified as a Temporary Employee, as defined below, except that Davis-Bacon Employees described in Paragraph G-4 of Supplement G to the Plan who are Temporary Employees will become Eligible Employees upon the completion of one Hour of Service. "Temporary Employee" means an Employee classified as a temporary employee by an Employer and assigned employment status code 5 in the Knife River Corporation payroll system, employment status code 7 in the Montana-Dakota Utilities Co. or WBI Energy, Inc. payroll system, code N in the MDU Construction Services Group, Inc. payroll system, or any successor or equivalent payroll system code. A student, intern, or Temporary Employee who has completed more than 1,000 hours of service within a twelve-month period ending on or before December 31, 2010 shall be an Eligible Employee.

<u>Explanation: This amendment clarifies a temporary employee in the definition of "Eligible Employee" at the request of the Internal Revenue Service.</u>

2. By replacing the term "Compensation" with the term "Section 415 compensation (as defined in Section 3.7)" where the former term appears in the first sentence of Section 11.2(a) of the Plan.

<u>Explanation: This amendment clarifies that top heavy minimum contributions under the Plan are based on Participants' compensation under Section 415(c)(3) of the Code.</u>

3. By replacing the words "must be compensated for 1,000 Hours of Service" with the words "must be credited with 1,000 Hours of Service" where the former words appear in Section D-1-2 <u>Eligibility to Share in the Profit Sharing Feature</u> of Supplement D-1.

Explanation: This amendment clarifies the use of the term "Hours of Service" at the request of the Internal Revenue Service.

4. Effective as of January 1, 2010, by replacing the words "compensated for at least 1,000 Hours of Service" with the words "credited with at least 1,000 Hours of Service" wherever the former words appear throughout Supplement D-1 through D-7 and the applicable Addendums.

Explanation: This amendment clarifies the use of the term "Hours of Service" at the request of the Internal Revenue Service.

5. Effective as of January 1, 2010, by replacing the words "compensated for 1,000 Hours of Service" with the words "credited with 1,000 Hours of Service" wherever the former words appear throughout Supplement D-1 through D-7 and the applicable Addendums.

Explanation: This amendment clarifies the use of the term "Hours of Service" at the request of the Internal Revenue Service.

6. By replacing Section G-10 Contribution Limitation of Supplement G with the following:

G-10 Contribution Limitation. If the annual additions that would otherwise be allocated to a Davis-Bacon Employee's Accounts would exceed the limitations described in Section 3.7 of the Plan for any Plan Year, any portion of the excess amount that is attributable to contributions made on behalf of the Davis-Bacon Employee with respect to Davis-Bacon Service shall be corrected in accordance with Section 3.7 of the Plan.

Explanation: This amendment clarifies that excess annual additions under Supplement G are corrected in accordance with Section 3.7 of the Plan.

IN WITNESS WHEREOF, MDU Resources Group, Inc., as Sponsoring Employer of the Plan, has caused this amendment to be duly executed by a member of the MDU Resources Group, Inc. Employee Benefits Committee ("EBC") on this 25th day of November 2014.

MDU RESOURCES GROUP, INC.
EMPLOYEE BENEFITS COMMITTEE

By: /s/ Doran N. Schwartz
Doran N. Schwartz, Chairman

INSTRUMENT OF AMENDMENT TO THE
MDU RESOURCES GROUP, INC.
401(k) RETIREMENT PLAN

The MDU Resources Group, Inc. 401(k) Retirement Plan (as amended and restated March 1, 2011) (the "K-Plan"), is hereby further amended, effective January 1, 2014, unless otherwise indicated, as follows:

By replacing the table in Section D-1-2 Eligibility to Share in the Profit Sharing Feature of Supplement D-1, Provisions Relating to the Profit Sharing Feature for certain Participating Affiliates, in its entirety, with the following:

Participating Affiliate	**Current Effective Date (Original Effective Date)** [2]
Anchorage Sand & Gravel Company, Inc. (excluding President)	January 1, 1999
Baldwin Contracting Company, Inc.	January 1, 1999
Capital Electric Line Builders, Inc. [1]	January 1, 2014
Cascade Natural Gas Corporation	January 1, 2011 (July 2, 2007)
Concrete, Inc.	January 1, 2001
Connolly-Pacific Co.	January 1, 2007
DSS Company	January 1, 2004 (July 8, 1999)
E.S.I., Inc.	January 1, 2008 (January 1, 2003)
Fairbanks Materials, Inc.	May 1, 2008
Granite City Ready Mix, Inc.	June 1, 2002
Great Plains Natural Gas Co.	January 1, 2008
Hawaiian Cement (non-union employees hired after December 31, 2005)	January 1, 2009

Participating Affiliate	**Current Effective Date (Original Effective Date)** [2]
Intermountain Gas Company	January 1, 2011
JTL Group, Inc. [5]	January 1, 2014
Jebro Incorporated	November 1, 2005
Kent's Oil Service [4]	January 1, 2007
Knife River Corporation – Northwest (the Central Oregon Division, f/k/a HTS)	January 1, 2010 (January 1, 1999)
Knife River Corporation – Northwest (the Southern Idaho Division)	January 1, 2010 (January 1, 2006)
Knife River Corporation – Northwest (the Southern Oregon Division)	January 1, 2012
Knife River Corporation – Northwest (the Spokane Division)	January 1, 2010 (January 1, 2006)
Knife River Corporation – Northwest (the Western Oregon Division)	January 1, 2012
Knife River Corporation - South (f/k/a Young Contractors, Inc.)	January 1, 2008 (January 1, 2007)
LTM, Incorporated	January 1, 2003
Montana-Dakota Utilities Co. (including union employees)	January 1, 2008
Oregon Electric Construction, Inc. [3]	March 7, 2011
Wagner Industrial Electric, Inc.	January 1, 2008
Wagner Smith Equipment Co.	January 1, 2008 (July 1, 2000)
WBI Energy, Inc. [1/3]	May 1, 2012

Participating Affiliate	Current Effective Date (Original Effective Date) [2]
WBI Energy Midstream, LLC [1/3]	July 1, 2012 (January 1, 2001)
WBI Energy Midstream Utah, LLC [1/3]	August 1, 2014
WBI Energy Transmission, Inc. [1/3]	July 1, 2012 (January 1, 2009)
WHC, Ltd.	September 1, 2001

[1/] Eligible employees participating in a management incentive compensation plan or an executive incentive compensation plan are not eligible for a Profit Sharing Contribution. Employees of the WBI Energy Corrosion Services division of WBI Energy Midstream, LLC are excluded from this feature.

[2/] In the event a Participating Affiliate adopts a Profit Sharing Feature on a date other than January 1, effective as of the date of participation in the Plan, the amount of any such contribution allocated to a Supplement D−1 Participant shall be based upon Compensation, received while in the employ of the Participating Affiliate after the date of acquisition by the Company or any Affiliate.

[3/] Requirement to be an Active Employee on the last day of the Plan Year does not apply.

[4/] The following participants of Kent's Oil Service are granted vesting service for prior years of service with Spirit Road Oils: Isaias Jaimes, Hideo Lewis, Christopher Niffenegger, Jose Padilla, George Velador, and Anthony Willis.

[5/] Eligible JTL Casper hourly employees (both union and nonunion), including those employees who participate in the Operating Engineers Local No. 800 & The Wyoming Contractors' Association, Inc. Pension Trust Fund for Wyoming (JTL MEP employees).

Explanation: This amendment adds JTL Group, Inc. (JTL) as a Participating Affiliate in Supplement D-1 (Profit Sharing Feature) of the K-Plan as of January 1, 2014 due to its desire to participate in the Profit Sharing Feature for its Casper hourly employees (union and nonunion), including those who participate in the Operating Engineers Local No. 800 & The Wyoming Contractors' Association, Inc. Pension Trust Fund for Wyoming.

IN WITNESS WHEREOF, MDU Resources Group, Inc., as Sponsoring Employer of the Plan, has caused this amendment to be duly executed by a member of the MDU Resources Group, Inc. Employee Benefits Committee ("Committee") on this 11th day of December, 2014.

MDU RESOURCES GROUP, INC.
EMPLOYEE BENEFITS COMMITTEE

By: /s/ Doran N. Schwartz
Doran N. Schwartz, Chairman

**INSTRUMENT OF AMENDMENT TO THE
MDU RESOURCES GROUP, INC.
401(k) RETIREMENT PLAN**

The MDU Resources Group, Inc. 401(k) Retirement Plan (as amended and restated March 1, 2011) (the "K-Plan"), is hereby further amended, as follows:

1. Effective January 1, 2014, by replacing the table in Section D-1-2 Eligibility to Share in the Profit Sharing Feature of Supplement D-1, Provisions Relating to the Profit Sharing Feature for certain Participating Affiliates, in its entirety, with the following:

Participating Affiliate	**Current Effective Date (Original Effective Date)** [2]
Anchorage Sand & Gravel Company, Inc. (excluding President)	January 1, 1999
Baldwin Contracting Company, Inc.	January 1, 1999
Capital Electric Line Builders, Inc. [1]	January 1, 2014
Cascade Natural Gas Corporation	January 1, 2011 (July 2, 2007)
Concrete, Inc.	January 1, 2001
Connolly-Pacific Co.	January 1, 2007
DSS Company	January 1, 2004 (July 8, 1999)
E.S.I., Inc.	January 1, 2008 (January 1, 2003)
Fairbanks Materials, Inc.	May 1, 2008
Granite City Ready Mix, Inc.	June 1, 2002
Great Plains Natural Gas Co.	January 1, 2008

Participating Affiliate	Current Effective Date (Original Effective Date) [2]
Hawaiian Cement (non-union employees hired after December 31, 2005)	January 1, 2009
Intermountain Gas Company	January 1, 2011
JTL Group, Inc. [5]	January 1, 2014
Jebro Incorporated	November 1, 2005
Kent's Oil Service [4]	January 1, 2007
Knife River Corporation – Northwest (the Central Oregon Division, f/k/a HTS)	January 1, 2010 (January 1, 1999)
Knife River Corporation – Northwest (the Southern Idaho Division)	January 1, 2010 (January 1, 2006)
Knife River Corporation – Northwest (the Southern Oregon Division)	January 1, 2012
Knife River Corporation – Northwest (the Spokane Division)	January 1, 2010 (January 1, 2006)
Knife River Corporation – Northwest (the Utah Division)	January 1, 2014
Knife River Corporation – Northwest (the Western Oregon Division)	January 1, 2012
Knife River Corporation - South (f/k/a Young Contractors, Inc.)	January 1, 2008 (January 1, 2007)
LTM, Incorporated	January 1, 2003
Montana-Dakota Utilities Co. (including union employees)	January 1, 2008
Oregon Electric Construction, Inc. [3]	March 7, 2011
Wagner Industrial Electric, Inc.	January 1, 2008

Participating Affiliate	Current Effective Date (Original Effective Date) [2]
Wagner Smith Equipment Co.	January 1, 2008 (July 1, 2000)
WBI Energy, Inc. [1/3]	May 1, 2012
WBI Energy Midstream, LLC [1/3]	July 1, 2012 (January 1, 2001)
WBI Energy Midstream Utah, LLC [1/3]	August 1, 2014
WBI Energy Transmission, Inc. [1/3]	July 1, 2012 (January 1, 2009)
WHC, Ltd.	September 1, 2001

[1/] Eligible employees participating in a management incentive compensation plan or an executive incentive compensation plan are not eligible for a Profit Sharing Contribution. Employees of the WBI Energy Corrosion Services division of WBI Energy Midstream, LLC are excluded from this feature.

[2/] In the event a Participating Affiliate adopts a Profit Sharing Feature on a date other than January 1, effective as of the date of participation in the Plan, the amount of any such contribution allocated to a Supplement D–1 Participant shall be based upon Compensation, received while in the employ of the Participating Affiliate after the date of acquisition by the Company or any Affiliate.

[3/] Requirement to be an Active Employee on the last day of the Plan Year does not apply.

[4/] The following participants of Kent's Oil Service are granted vesting service for prior years of service with Spirit Road Oils: Isaias Jaimes, Hideo Lewis, Christopher Niffenegger, Jose Padilla, George Velador, and Anthony Willis.

[5/] Eligible JTL Casper hourly employees (both union and nonunion), including those employees who participate in the Operating Engineers Local No. 800 & The Wyoming Contractors' Association, Inc. Pension Trust Fund for Wyoming (JTL MEP employees.)

Explanation: This amendment adds Knife River Corporation – Northwest (Utah Division) ("KR-Utah") as a Participating Affiliate in Supplement D-1 (Profit Sharing Feature) of the K−Plan as of January 1, 2014, due to its desire to participate in the Profit Sharing Feature.

2. Effective January 1, 2015, by replacing the table in Section D-1-2 Eligibility to Share in the Profit Sharing Feature of Supplement D-1, Provisions Relating to the Profit Sharing Feature for certain Participating Affiliates, in its entirety, with the following:

Participating Affiliate	Current Effective Date (Original Effective Date) [2]
Anchorage Sand & Gravel Company, Inc. (excluding President)	January 1, 1999

Participating Affiliate	**Current Effective Date (Original Effective Date)** [2]
Baldwin Contracting Company, Inc.	January 1, 1999
Capital Electric Line Builders, Inc. [1]	January 1, 2014
Cascade Natural Gas Corporation	January 1, 2011 (July 2, 2007)
Concrete, Inc.	January 1, 2001
Connolly-Pacific Co.	January 1, 2007
DSS Company	January 1, 2004 (July 8, 1999)
E.S.I., Inc.	January 1, 2008 (January 1, 2003)
Fairbanks Materials, Inc.	May 1, 2008
Granite City Ready Mix, Inc.	June 1, 2002
Great Plains Natural Gas Co.	January 1, 2008
Hawaiian Cement (non-union employees hired after December 31, 2005)	January 1, 2009
Intermountain Gas Company	January 1, 2011
JTL Group, Inc. [5/6]	January 1, 2015 January 1, 2014
Jebro Incorporated	November 1, 2005
Kent's Oil Service [4]	January 1, 2007
Knife River Corporation – Northwest (the Central Oregon Division, f/k/a HTS)	January 1, 2010 (January 1, 1999)

Participating Affiliate	**Current Effective Date (Original Effective Date)** [2]
Knife River Corporation – Northwest (the Idaho Division)	January 1, 2015
Knife River Corporation – Northwest (the Southern Oregon Division)	January 1, 2012
Knife River Corporation – Northwest (the Western Oregon Division)	January 1, 2012
Knife River Corporation - South (f/k/a Young Contractors, Inc.)	January 1, 2008 (January 1, 2007)
LTM, Incorporated	January 1, 2003
Montana-Dakota Utilities Co. (including union employees)	January 1, 2008
Oregon Electric Construction, Inc. [3]	March 7, 2011
Wagner Industrial Electric, Inc.	January 1, 2008
Wagner Smith Equipment Co.	January 1, 2008 (July 1, 2000)
WBI Energy, Inc. [1/3]	May 1, 2012
WBI Energy Midstream, LLC [1/3]	July 1, 2012 (January 1, 2001)
WBI Energy Midstream Utah, LLC [1/3]	August 1, 2014
WBI Energy Transmission, Inc. [1/3]	July 1, 2012 (January 1, 2009)
WHC, Ltd.	September 1, 2001

[1/] Eligible employees participating in a management incentive compensation plan or an executive incentive compensation plan are not eligible for a Profit Sharing Contribution. Employees of the WBI Energy Corrosion Services division of WBI Energy Midstream, LLC are excluded from this feature.

[2/] In the event a Participating Affiliate adopts a Profit Sharing Feature on a date other than January 1, effective as of the date of participation in the Plan, the amount of any such contribution allocated to a

Supplement D−1 Participant shall be based upon Compensation, received while in the employ of the Participating Affiliate after the date of acquisition by the Company or any Affiliate.

[3/] Requirement to be an Active Employee on the last day of the Plan Year does not apply.

[4/] The following participants of Kent's Oil Service are granted vesting service for prior years of service with Spirit Road Oils: Isaias Jaimes, Hideo Lewis, Christopher Niffenegger, Jose Padilla, George Velador, and Anthony Willis.

[5/] Eligible JTL Casper hourly employees (both union and nonunion), including those employees who participate in the Operating Engineers Local No. 800 & The Wyoming Contractors' Association, Inc. Pension Trust Fund for Wyoming (JTL MEP employees.)

[6/] Eligible salaried employees of JTL hired after December 31, 2014 or any other JTL employee who transfers to a salaried position after December 31, 2014.

Explanation: This amendment adds Knife River Corporation – Northwest (Idaho Division) ("KR-Idaho") and removes the SID Idaho Division, Spokane Division, and Utah Division as Participating Affiliates in Supplement D-1 (Profit Sharing Feature) of the K−Plan as the result of consolidation of divisions within KRC – NW as of January 1, 2015. This amendment adds a Profit Sharing Feature for salaried employees of JTL Group, Inc. hired after December 31, 2014 and any other JTL employee who transfers to a salaried position after December 31, 2014.

3. Effective January 1, 2015, by replacing Section D-7-3, Amount of Retirement Contribution Allocation, of Supplement D-7, Provisions Relating to the JTL Group, Inc. Retirement Contribution Feature , in its entirety, with the following:

For each Plan Year, JTL shall provide eligible hourly Participants $1.55 (effective April 1, 2014) per hour of service as a Retirement Contribution. The amount of any such contribution for a Plan Year will be allocated to Supplement D-7 hourly Participants for each hour of service for which the Participant receives compensation, excluding Hours of Service pursuant to a prevailing wage agreement. In addition, JTL will credit eligible salaried Participants with a contribution equal to eight percent (8%) of Compensation. Salaried Participants must have been hired and classified as a salaried employee prior to January 1, 2015 in order to receive a Retirement Contribution allocation. The amount of any such Retirement Contribution for a Plan Year shall be allocated to Supplement D−7 Participants based upon their Compensation, excluding bonuses received while employed by the identified Participating Affiliate.

Explanation: This amendment closes the group of employees who receive the 8 percent Retirement Contribution. Any employee hired or who becomes classified as salaried employee after December 31, 2014 will not be eligible to participate in the Retirement Contribution Feature.

IN WITNESS WHEREOF, MDU Resources Group, Inc., as Sponsoring Employer of the Plan, has caused this amendment to be duly executed by a member of the MDU Resources Group, Inc. Employee Benefits Committee ("Committee") on this 11th day of

December, 2014.

MDU RESOURCES GROUP, INC.
EMPLOYEE BENEFITS COMMITTEE

By: /s/ Doran N. Schwartz
Doran N. Schwartz, Chairman

**INSTRUMENT OF AMENDMENT TO THE
MDU RESOURCES GROUP, INC.
401(k) RETIREMENT PLAN**

The MDU Resources Group, Inc. 401(k) Retirement Plan (as amended and restated March 1, 2011) (the "K-Plan"), is hereby further amended as follows:

1. Effective June 26, 2013, by replacing the definition of "Spouse" in Article I of the K−Plan with the following:

    Spouse – A "Spouse" means the legally married spouse of a Participant determined in accordance with IRS and/or Department of Labor guidance applicable to the Plan. Prior to June 26, 2013, "Spouse" means only the Participant's lawful opposite-sex spouse. From June 26, 2013 through September 15, 2013, the Plan also recognizes the marriage of a Participant to a same-sex spouse that was valid in the state where it was entered into provided the Participant is domiciled in a state that recognizes same−sex marriages. Effective September 16, 2013, the Plan also recognizes the marriage of a Participant to a same-sex spouse that was valid in the state where it was entered into regardless of whether the Participant is domiciled in a state that recognizes same-sex marriages.

Explanation: This amendment changes the definition of spouse as legislatively required.

IN WITNESS WHEREOF, MDU Resources Group, Inc., as Sponsoring Employer of the Plan, has caused this amendment to be duly executed by a member of the MDU Resources Group, Inc. Employee Benefits Committee ("Committee") on this 30th day of December, 2014.

MDU RESOURCES GROUP, INC.
EMPLOYEE BENEFITS COMMITTEE

By: /s/ Doran N. Schwartz
Doran N. Schwartz, Chairman

MDU Resources Group, Inc. Section 16 Officers and Directors
with Indemnification Agreements Chart

Section 16 Officers

Name	**Title**	**Date of Agreement**
David L. Goodin	President and Chief Executive Officer, MDU Resources Group, Inc.	August 12, 2010, as amended May 15, 2014
Steven L. Bietz	President and Chief Executive Officer, WBI Holdings, Inc.	August 12, 2010, as amended May 15, 2014
William R. Connors	Vice President - Renewable Resources, MDU Resources Group, Inc.	August 12, 2010, as amended May 15, 2014
Mark A. Del Vecchio	Vice President - Human Resources, MDU Resources Group, Inc.	August 12, 2010, as amended May 15, 2014
Cynthia J. Norland	Vice President - Administration, MDU Resources Group, Inc.	August 12, 2010, as amended May 15, 2014
Paul K. Sandness	General Counsel and Secretary, MDU Resources Group, Inc.	August 12, 2010, as amended May 15, 2014
Doran N. Schwartz	Vice President and Chief Financial Officer, MDU Resources Group, Inc.	August 12, 2010, as amended May 15, 2014
Douglass A. Mahowald	Treasurer and Assistant Secretary, MDU Resources Group, Inc. through November 28, 2014	August 12, 2010, as amended May 15, 2014
Nicole A. Kivisto	President and Chief Executive Officer, Montana- Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective January 9, 2015	August 12, 2010, as amended May 15, 2014
J. Kent Wells	Vice Chairman, MDU Resources Group, Inc.; and Chief Executive Officer, Fidelity Exploration & Production Company	May 2, 2011, as amended May 15, 2014
K. Frank Morehouse	President and Chief Executive Officer, Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company through January 8, 2015	January 4, 2013, as amended May 15, 2014
David C. Barney	President and Chief Executive Officer, Knife River Corporation	May 16, 2013, as amended May 15, 2014
Jeffrey S. Thiede	President and Chief Executive Officer, MDU Construction Services Group, Inc.	May 16, 2013, as amended May 15, 2014
Dennis L. Haider	Executive Vice President - Business Development, MDU Resources Group, Inc.	June 1, 2013, as amended May 15, 2014
Nathan W. Ring	Vice President, Controller and Chief Accounting Officer, MDU Resources Group, Inc.	January 3, 2014, as amended May 15, 2014
Jason L. Vollmer	Treasurer and Director of Cash and Risk Management, MDU Resources Group, Inc. effective November 29, 2014	November 29, 2014

Directors

Name	Title	Date of Agreement
Harry J. Pearce	Chairman of the Board of Directors	August 12, 2010
David L. Goodin	Director	August 12, 2010
Thomas Everist	Director	August 12, 2010
Karen B. Fagg	Director	August 12, 2010
Mark A. Hellerstein	Director	August 1, 2013
A. Bart Holaday	Director	August 12, 2010
Dennis W. Johnson	Director	August 12, 2010
William E. McCracken	Director	August 1, 2013
Patricia L. Moss	Director	August 12, 2010
J. Kent Wells	Director	May 2, 2011
John K. Wilson	Director	August 12, 2010

MDU RESOURCES GROUP, INC.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
AND COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(In thousands of dollars)				
Earnings Available for Fixed Charges:					
Net Income (a)	$ 291,711	$ 281,163	$ (14,939)	$ 223,842	$ 218,205
Income Taxes	119,969	136,736	(31,146)	110,273	122,530
	411,680	417,899	(46,085)	334,115	340,735
Rents (b)	17,902	16,035	13,716	13,568	12,897
Interest (c)	94,758	92,481	83,781	86,505	88,930
Total Earnings Available for Fixed Charges	$ 524,340	$ 526,415	$ 51,412	$ 434,188	$ 442,562
Preferred Dividend Requirements	$ 685	$ 685	$ 685	$ 685	$ 685
Ratio of Income Before Income Taxes to Net Income	141%	149%	308%	149%	156%
Preferred Dividend Factor on Pretax Basis	966	1,021	2,110	1,021	1,069
Fixed Charges (d)	115,695	107,892	100,516	106,348	107,552
Combined Fixed Charges and Preferred Stock Dividends	$ 116,661	$ 108,913	$ 102,626	$ 107,369	$ 108,621
Ratio of Earnings to Fixed Charges	4.5x	4.9x	— (e)	4.1x	4.1x
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	4.5x	4.8x	— (e)	4.0x	4.1x

(a) Net income excludes undistributed income for equity investees.

(b) Represents interest portion of rents estimated at 33 1/3%.

(c) Represents interest, amortization of debt discount and expense on all indebtedness and amortization of interest capitalized, and excludes amortization of gains or losses on reacquired debt (which, under the Federal Energy Regulatory Commission Uniform System of Accounts, is classified as a reduction of, or increase in, interest expense in the Consolidated Statements of Income) and interest capitalized.

(d) Represents rents (as defined above), interest, amortization of debt discount and expense on all indebtedness, and excludes amortization of gains or losses on reacquired debt (which, under the Federal Energy Regulatory Commission Uniform System of Accounts, is classified as a reduction of, or increase in, interest expense in the Consolidated Statements of Income).

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

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

MDU RESOURCES GROUP, INC.
List of Subsidiaries
(effective December 31, 2014)

Subsidiaries	Jurisdiction of Formation
Alaska Basic Industries, Inc.	Alaska
Ames Sand & Gravel, Inc.	North Dakota
Anchorage Sand and Gravel Company, Inc.	Alaska
Baldwin Contracting Company, Inc.	California
BEH Electric Holdings, LLC	Nevada
Bell Electrical Contractors, Inc.	Missouri
BMH Mechanical Holdings, LLC	Nevada
Bombard Electric, LLC	Nevada
Bombard Mechanical, LLC	Nevada
Capital Electric Construction Company, Inc.	Kansas
Capital Electric Line Builders, Inc.	Kansas
Cascade Natural Gas Corporation	Washington
Centennial Energy Holdings, Inc.	Delaware
Centennial Energy Resources International, Inc.	Delaware
Centennial Energy Resources LLC	Delaware
Centennial Holdings Capital LLC	Delaware
Central Oregon Redi-Mix, LLC	Oregon
CGC Resources, Inc.	Washington
Concrete, Inc.	California
Connolly-Pacific Co.	California
Continental Line Builders, Inc.	Delaware
Coordinating and Planning Services, Inc.	Delaware
D S S Company	California
Desert Fire Holdings, Inc.	Nevada
Desert Fire Protection, a Nevada Limited Partnership	Nevada
Desert Fire Protection, Inc.	Nevada
Desert Fire Protection, LLC	Nevada
E.S.I., Inc.	Ohio
Fairbanks Materials, Inc.	Alaska
Fidelity Exploration & Production Company	Delaware
Fidelity Oil Co.	Delaware
Frebco, Inc.	Ohio
FutureSource Capital Corp.	Delaware
Granite City Ready Mix, Inc.	Minnesota
Hamlin Electric Company	Colorado
Harp Engineering, Inc.	Montana
Hawaiian Cement, a partnership	Hawaii
ILB Hawaii, Inc.	Hawaii

Independent Fire Fabricators, LLC	Nevada
Intermountain Gas Company	Idaho
International Line Builders, Inc.	Delaware
InterSource Insurance Company	Vermont
Jebro Incorporated	Iowa
JTL Group, Inc. (Montana corporation)	Montana
JTL Group, Inc. (Wyoming corporation)	Wyoming
Kent’s Oil Service	California
Knife River Corporation	Delaware
Knife River Corporation - North Central	Minnesota
Knife River Corporation - Northwest	Oregon
Knife River Corporation - South	Texas
Knife River Dakota, Inc.	Delaware
Knife River Hawaii, Inc.	Delaware
Knife River Marine, Inc.	Delaware
Knife River Midwest, LLC	Delaware
KRC Holdings, Inc.	Delaware
LME&U Holdings, LLC	Nevada
Lone Mountain Excavation & Utilities, LLC	Nevada
Loy Clark Pipeline Co.	Oregon
LTM, Incorporated	Oregon
MDU Brasil Ltda.	Brazil
MDU Construction Services Group, Inc.	Delaware
MDU Energy Capital, LLC	Delaware
MDU Industrial Services, Inc.	Delaware
MDU Resources International LLC	Delaware
MDU Resources Luxembourg I LLC S.a.r.l.	Luxembourg
MDU Resources Luxembourg II LLC S.a.r.l.	Luxembourg
MDU United Construction Solutions, Inc.	Delaware
Midland Technical Crafts, Inc.	Delaware
Nevada Solar Solutions, LLC	Delaware
Northstar Materials, Inc.	Minnesota
Oregon Electric Construction, Inc.	Oregon
Pouk & Steinle, Inc.	California
Prairie Cascade Energy Holdings, LLC	Delaware
Prairie Intermountain Energy Holdings, LLC	Delaware
Prairielands Energy Marketing, Inc.	Delaware
Rocky Mountain Contractors, Inc.	Montana
USI Industrial Services, Inc.	Delaware
Wagner Group, Inc., The	Delaware
Wagner Industrial Electric, Inc.	Delaware
Wagner-Smith Company, The	Ohio
Wagner-Smith Equipment Co.	Delaware
Wagner-Smith Pumps & Systems, Inc.	Ohio
Warner Enterprises, Inc.	Nevada
WBI Canadian Pipeline, Ltd.	Canada

WBI Energy Midstream Utah, LLC	Delaware
WBI Energy Midstream, LLC	Colorado
WBI Energy Services, Inc.	Delaware
WBI Energy Transmission, Inc.	Delaware
WBI Energy Wind Ridge Pipeline, LLC	Delaware
WBI Energy, Inc.	Delaware
WBI Holdings, Inc.	Delaware
WHC, Ltd.	Hawaii

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements No. 333-195990 and No. 333-200174 on Form S-3, and No. 333-27877, No. 333-118622, No. 333-114488, and No. 333-198364 on Form S-8, of our reports dated February 20, 2015, relating to the consolidated financial statements and financial statement schedules of MDU Resources Group, Inc. and subsidiaries (the “Company”), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10−K of the Company for the year ended December 31, 2014.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 20, 2015

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

CONSENT OF RYDER SCOTT COMPANY, L.P.

As independent oil and gas consultants, Ryder Scott Company, L.P. hereby consents to the incorporation by reference in Registration Statement No. 333-195990 and No. 333-200174 on Form S-3, and No. 333-27877, No. 333-118622, No. 333-114488, and No. 333-198364 on Form S-8, of all references to our firm's name and audit of portions of Fidelity Exploration & Production Company's ("Fidelity") proved oil, NGL and natural gas reserves estimates as of December 31, 2014, as described in our letter to Fidelity dated January 29, 2015, included in or made a part of MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2014. Ryder Scott Company, L.P. recognizes Fidelity is an indirect wholly owned subsidiary of MDU Resources Group, Inc. who makes filings with the Securities and Exchange Commission.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm License No. F-1580

Houston, Texas
February 20, 2015

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

CERTIFICATION

I, David L. Goodin, certify that:

1. I have reviewed this annual report on Form 10-K of MDU Resources Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2015

/s/ David L. Goodin
David L. Goodin
President and Chief Executive Officer

CERTIFICATION

I, Doran N. Schwartz, certify that:

1. I have reviewed this annual report on Form 10-K of MDU Resources Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2015

/s/ Doran N. Schwartz
Doran N. Schwartz
Vice President and Chief Financial Officer

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

Each of the undersigned, David L. Goodin, the President and Chief Executive Officer, and Doran N. Schwartz, the Vice President and Chief Financial Officer of MDU Resources Group, Inc. (the "Company"), DOES HEREBY CERTIFY that:

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2014 (the "Report"), fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, each of the undersigned has executed this statement this 20 th day of February, 2015 .

/s/ David L. Goodin
David L. Goodin
President and Chief Executive Officer

/s/ Doran N. Schwartz
Doran N. Schwartz
Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to MDU Resources Group, Inc. and will be retained by MDU Resources Group, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

MDU RESOURCES GROUP, INC.
MINE SAFETY INFORMATION

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Act), as amended by the Mine Improvement and New Emergency Response Act of 2006 (Mine Safety Act). The Dodd-Frank Act requires reporting of the following types of citations or orders:

1. Citations issued under Section 104 of the Mine Safety Act for violations that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard.
2. Orders issued under Section 104(b) of the Mine Safety Act. Orders are issued under this section when citations issued under Section 104 have not been totally abated within the time period allowed by the citation or subsequent extensions.
3. Citations or orders issued under Section 104(d) of the Mine Safety Act. Citations or orders are issued under this section when it has been determined that the violation is caused by an unwarrantable failure of the mine operator to comply with the standards. An unwarrantable failure occurs when the mine operator is deemed to have engaged in aggravated conduct constituting more than ordinary negligence.
4. Citations issued under Section 110(b)(2) of the Mine Safety Act for flagrant violations. Violations are considered flagrant for repeat or reckless failures to make reasonable efforts to eliminate a known violation of a mandatory health and safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury.
5. Imminent danger orders issued under Section 107(a) of the Mine Safety Act. An imminent danger is defined as the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated.
6. Notice received under Section 104(e) of the Mine Safety Act of a pattern of violations or the potential to have such a pattern of violations that could significantly and substantially contribute to the cause and effect of mine health and safety standards.

During the twelve months ended December 31, 2014 , none of the Company's operating subsidiaries received citations or orders under the following sections of the Mine Safety Act: 104(d), 110(b)(2) or 104(e). During the twelve months ended December 31, 2014, one of the Company's operating subsidiaries received orders under Section 104(b) of the Mine Safety Act and three of the Company's operating subsidiaries received orders under Section 107(a) of the Mine Safety Act. The Company did not have any mining-related fatalities during this period.

MSHA Identification Number/Contractor ID	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
04-00081	3	—	1	$ 920	8	4	—
04-01698	—	—	—	200	—	1	1
04-05140	—	—	—	200	—	—	—
04-05156	—	—	—	100	—	—	—
04-05459	—	—	—	100	2	1	—
10-02170	—	—	—	400	—	—	—
13-02222	1	—	—	208	—	—	—
21-00462	1	—	1	—	—	—	1
21-02702	—	—	—	200	—	—	—
21-02718	—	—	—	100	—	—	—
21-03096	—	—	—	400	—	—	—
21-03127	1	—	—	—	—	—	—
21-03185	1	—	—	317	—	1	1
21-03248	1	—	—	276	—	1	1
21-03348	—	—	—	200	—	—	—
21-03358	—	—	—	200	—	—	—
21-03560	—	—	—	100	—	—	—
21-03626	—	—	—	100	—	—	—
21-03812	—	—	—	300	—	—	—
24-00459	1	—	—	862	—	—	—
24-00462	—	—	—	400	—	—	—
24-00478	1	—	—	508	—	1	1
24-02022	2	—	—	1,858	—	—	1
24-02095	—	—	—	100	—	—	—
24-02414	—	—	—	600	—	—	—
32-00774	—	1	—	100	—	—	—
32-00776	1	—	—	362	—	—	—
32-00777	—	—	—	100	—	—	—
32-00778	—	—	—	576	—	—	—
32-00950	—	—	—	200	—	—	2
32-00963	2	—	—	1,124	—	—	—
32-00966	—	—	—	100	—	—	—
32-00967	—	—	—	100	—	—	—
35-00463	—	—	—	300	—	—	—
35-00495	1	—	—	1,060	—	—	—
35-00512	1	—	—	790	—	—	—
35-00521	1	—	—	662	—	—	—
35-02968	—	—	—	400	—	—	—
35-03022	—	—	—	300	—	—	—
35-03321	1	—	—	602	—	—	—
35-03404	—	—	—	200	—	2	2
35-03449	—	—	—	200	—	—	—
35-03478	1	—	—	762	—	—	—

MSHA Identification Number/Contractor ID	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
35-03496	—	—	—	700	—	—	—
35-03505	2	—	—	1,024	3	3	—
35-03527	1	—	—	2,674	—	—	—
35-03581	1	—	—	762	—	—	—
35-03595	1	—	—	725	—	—	—
35-03605	—	—	—	200	—	—	—
35-03642	1	—	—	217	—	—	—
35-03667	2	—	—	909	—	—	—
35-03752	—	—	—	200	—	—	—
41-02639	—	—	—	200	—	—	—
41-03931	—	—	—	200	—	—	—
48-00715	1	—	—	308	—	—	—
48-01383	—	—	—	823	—	—	—
48-01670	—	—	—	200	—	—	—
50-01196	—	—	—	100	—	—	—
51-00036	—	—	—	5,487	4	—	1
51-00171	—	—	—	100	—	—	—
51-00192	1	—	1	3,884	1	1	—
B0402 (Contractor ID)	1	—	—	217	—	—	—
	31	1	3	$ 35,517	18	15	11

Legal actions pending before the Federal Mine Safety and Health Review Commission (the Commission) may involve, among other questions, challenges by operators to citations, orders and penalties they have received from the Federal Mine Safety and Health Administration (MSHA) or complaints of discrimination by miners under section 105 of the Mine Act. The following is a brief description of the types of legal actions that may be brought before the Commission.

- Contests of Citations and Orders - A contest proceeding may be filed with the Commission by operators, miners or miners' representatives to challenge the issuance of a citation or order issued by MSHA.
- Contests of Proposed Penalties (Petitions for Assessment of Penalties) - A contest of a proposed penalty is an administrative proceeding before the Commission challenging a civil penalty that MSHA has proposed for the alleged violation contained in a citation or order.
- Complaints for Compensation - A complaint for compensation may be filed with the Commission by miners entitled to compensation when a mine is closed by certain withdrawal orders issued by MSHA. The purpose of the proceeding is to determine the amount of compensation, if any, due miners idled by the orders.
- Complaints of Discharge, Discrimination or Interference - A discrimination proceeding is a case that involves a miner's allegation that he or she has suffered a wrong by the operator because he or she engaged in some type of activity protected under the Mine Act, such as making a safety complaint.
- Applications for Temporary Relief - Applications for temporary relief from any modification or termination of any order or from any order issued under section 104 of the Mine Act.
- Appeals of Judges' Decisions or Orders to the Commission - A filing with the Commission for discretionary review of a judge's decision or order by a person who has been adversely affected or aggrieved by such decision or order.

The following table reflects the types of legal actions pending before the Commission as of December 31, 2014 :

MSHA Identification Number	Contests of Citations and Orders	Contests of Proposed Penalties	Complaints for Compensation	Complaints of Discharge, Discrimination or Interference	Applications for Temporary Relief	Appeals of Judges' Decisions or Orders to the Commission
04-00081	1	3	—	—	—	4
04-05459	—	—	—	—	—	2
35-03505	3	—	—	—	—	—
51-00036	—	4	—	—	—	—
51-00192	1	—	—	—	—	—
	5	7	—	—	—	6

FIDELITY EXPLORATION & PRODUCTION COMPANY

Estimated

Future Reserves

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2014

/s/ Joseph E. Blankenship

Joseph E. Blankenship, P.E.
TBPE License No. 62093
Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 29, 2015

Fidelity Exploration & Production Company
1700 Lincoln, Suite 2800
Denver, Colorado 80203

Gentlemen:

At the request of Fidelity Exploration & Production Company (Fidelity), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2014 prepared by Fidelity's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Fidelity Exploration & Production Company is an indirect wholly owned subsidiary of MDU Resources (MDU).

Our reserves audit, completed on January 27, 2015 and presented herein, was prepared for public disclosure by MDU in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent Fidelity's estimated net reserves attributable to the leasehold and royalty interests in certain properties owned by Fidelity, which were all reviewed by Ryder Scott, as of December 31, 2014. The properties reviewed by Ryder Scott incorporate 3818 reserve determinations and are located in the states of Alabama, Arkansas, Colorado, Louisiana, Montana, New Mexico, North Dakota, Oklahoma, Texas, Utah, Wyoming, and in federal waters offshore Louisiana and Texas.

The properties reviewed by Ryder Scott account for 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Fidelity as of December 31, 2014.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities."

Based on our review, including the data, technical processes and interpretations presented by Fidelity, it is our opinion that the overall procedures and methodologies utilized by Fidelity in preparing their estimates of the proved reserves as of December 31, 2014 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Fidelity are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Fidelity has informed us that in the preparation of their reserve and income projections, as of December 31, 2014, they used average prices during the 12-month period prior to the "as of date" in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Fidelity attributable to Fidelity's interests in properties that we reviewed are summarized as follows:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold and Royalty Interests of
Fidelity Exploration & Production Company
As of December 31, 2014

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Total Net Reserves				
All Audited by Ryder Scott				
Oil/Condensate - Barrels	29,630,836	499,023	13,788,344	43,918,203
Plant Products - Barrels	3,466,865	749,806	2,970,132	7,186,803
Gas – MMCF	161,461	22,976	60,574	245,011

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10 (a) entitled “Petroleum Reserves Definitions” is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled “Petroleum Reserves Status Definitions and Guidelines” in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe categories.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Fidelity's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by Fidelity, for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 95 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation, which utilized extrapolations of historical production and pressure data available through October 2014, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Fidelity or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 5 percent of the proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

Approximately 100 percent of the proved developed non-producing and undeveloped reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Fidelity for our review or which we have obtained from public data sources that were available through October 2014. The data utilized from the analogues as well as well and seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

Fidelity's reserves are in conventional formations, coal seams and shales. Although most of Fidelity's reserves are based on primary recovery, some of Fidelity's reserves are based on secondary recovery; examples would include some of Fidelity's properties operated by Denbury Resources Inc. in Montana and North Dakota. Although most of Fidelity's reserves will be produced through vertical wellbores, some of Fidelity's reserves will be produced through horizontal wellbores; examples would include Fidelity's wells producing the Bakken Shale.

To estimate economically recoverable proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Fidelity relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Fidelity for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2014 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by Fidelity for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by Fidelity to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used by Fidelity were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Fidelity.

The table below summarizes Fidelity’s net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Fidelity’s “average realized prices.” The average realized prices shown in the table below were determined from Fidelity’s estimate of the total future gross revenue before production taxes for the properties reviewed by us and Fidelity’s estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$94.99/Bbl	$83.66/Bbl
	NGLs	WTI Cushing	$94.99/Bbl	$36.10/Bbl
	Gas	Henry Hub	$4.342/MMBTU	$5.11/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Fidelity’s individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserve estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs used by Fidelity are based on the operating expense reports of Fidelity and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished by Fidelity were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Fidelity. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Fidelity are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Fidelity were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Fidelity. The estimated net cost of abandonment after salvage was included by Fidelity for properties where abandonment costs net of salvage were significant. Fidelity's estimates of the net abandonment costs were accepted without independent verification.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Fidelity's plans to develop these reserves as of December 31, 2014. The implementation of Fidelity's development plans as presented to us is subject to the approval process adopted by Fidelity's management. As the result of our inquires during the course of our review, Fidelity has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Fidelity's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Fidelity. Additionally, Fidelity has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2014, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation. All of Fidelity's proved undeveloped reserves are scheduled to be developed within the five year window, from the first booked date, as prescribed by the SEC.

Current costs used by Fidelity were held constant throughout the life of the properties.

Fidelity's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend had been established, future production rates were held constant, or inclined during the dewatering phase for coal seam gas, as appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend had been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Fidelity to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Fidelity. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Fidelity's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Fidelity's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which Fidelity owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Fidelity for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Fidelity are responsible for the preparation of reserve estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Fidelity has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Fidelity's forecast of future proved production, we have relied upon data furnished by Fidelity with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Fidelity. The data described herein were accepted as authentic and sufficient for determining the reserves unless, during the course of our examination, a matter of question came to our attention in which case the data were not accepted until all questions were satisfactorily resolved. We consider the factual data furnished to us by Fidelity to be appropriate and sufficient for the purpose of our review of Fidelity's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Fidelity and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Fidelity, it is our opinion that the overall procedures and methodologies utilized by Fidelity in preparing their estimates of the proved reserves as of December 31, 2014 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Fidelity are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

We were in reasonable agreement with Fidelity's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Fidelity's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Fidelity when its reserve estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by Fidelity.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Fidelity. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

Fidelity Exploration & Production Company is an indirect wholly owned subsidiary of MDU Resources (MDU). The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by MDU.

MDU makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, MDU has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of MDU of the references to our name as well as to the references to our third party report for Fidelity, which appears in the December 31, 2014 annual report on Form 10-K of MDU. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by MDU.

We have provided Fidelity with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Fidelity and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Joseph E. Blankenship

Joseph E. Blankenship, P.E.
TBPE License No. 62093
Senior Vice President

[SEAL]

JEB (FWZ)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Joseph E. Blankenship was the primary technical person responsible for overseeing the estimation and evaluation process with respect to the preparation of this report.

Mr. Blankenship, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1982, is a Senior Vice President and also serves as Chief Technical Advisor for unconventional reserves evaluation. Mr. Blankenship is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Blankenship served in a number of engineering positions with Exxon Company USA. For more information regarding Mr. Blankenship's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees .

Mr. Blankenship earned a Bachelor of Science degree in Mechanical Engineering from the University of Alabama in 1977. He is a member of the Honorary Engineering Society Pi Tau Sigma and is a licensed Professional Engineer in the State of Texas. He attended Exxon schools on Reservoir Engineering, Well Log Analysis, Economic Evaluation, Oil and Gas Facility Design, and Offshore Platform Design. He is also a member of the Society of Petroleum Engineers (SPE) and the Society of Petroleum Evaluation Engineers (SPEE). He has served as Chairman of the SPE Newsletter Committee and has been invited by the SPEE to lecture on the subject of Coal Seam evaluation.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Blankenship fulfills. Mr. Blankenship's continuing education in 2014 included training on Aries Economic Evaluation Software, Nodal Analysis, Petrovisual Data Visualization Software, Petroleum Production Pricing, SEC vs. SPE PRMS Reserves Definitions, Probabilistic Evaluation Methods, Evaluation Quality Control and Quality Assurance, Reservoir Solutions Software, and Spotfire Business Intelligence Analytics Software. Mr. Blankenship also served as instructor in two courses on Unconventional and Conventional Reserves Evaluation.

In 2013, Mr. Blankenship's attended classes on Booking of Enhanced Oil Recovery (EOR) Reserves, Formation Fracturing Statistics, SEC Reserves Disclosures, Analysis of Shale Reserves, and Reserves Reconciliation. Mr. Blankenship also served as instructor in two courses on Unconventional Resource Evaluation.

In 2012, Mr. Blankenship attended classes on The Application of SPEE Monograph 3, Statistical Review of Shale Plays, the Simulation Model Review Process, A New SEC Data Gathering Program, Reserves Impact on Book Value Calculations, Comparison of Different Reserves Standards, Different Production Decline Models Used for Resource Plays, and Eagle Ford Shale Play Volumetric Analysis. Mr. Blankenship also served as instructor in some short courses on Unconventional Resource Evaluation.

Based on his educational background, professional training and more than 37 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Blankenship has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e. , absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e. , potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

> *(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*
>
> *(B) The project has been approved for development by all necessary parties and entities, including governmental entities.*

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate, but which have not started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.