MDU RESOURCES GROUP INC
Form 10-K
February 21, 2014

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

FORM 10-K

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

For the fiscal year ended December 31, 2013

OR

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

For the transition period from _____________ to ______________

Commission file number 1-3480

MDU Resources Group, Inc.
(Exact name of registrant as specified in its charter)

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

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

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

Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act:

Preferred Stock, par value $100
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ý No o.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No ý.

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting company)

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

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2013: $4,892,599,006.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 14, 2014: 189,370,016 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2014 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

2

Contents

Definitions

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
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)
Black Hills Power	Black Hills Power, Inc.
BLM	Bureau of Land Management
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
BOPD	Barrels of oil per day
Brazilian Transmission Lines	Company's investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and portions of the ownership interest in ECTE were sold in the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010)
Btu	British thermal unit
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CCU	Cane Creek Unit
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.
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant being built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
dk	Decatherm

Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation and amortization

ECTE	Empresa Catarinense de Transmissão de Energia S.A. (2.5 percent ownership interest at December 31, 2013, 2.5, 2.5, 2.5 and 14.99 percent ownership interests were sold in the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010, respectively)
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
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
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
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
MISO	Midcontinent Independent System Operator, Inc.
MMBOE	Millions of BOE

MMBtu	Million Btu

5

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
New York Supreme Court	Supreme Court of the State of New York, County of New York
NGL	Natural gas liquids
NSPS	New Source Performance Standards
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PDP	Proved developed producing
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2014 Proxy Statement
PRP	Potentially Responsible Party
psi	Pounds per square inch
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
SMCRA	Surface Mining Control and Reclamation Act
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

6

WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings (previously Bitter Creek Pipelines, LLC, name changed effective July 1, 2012)
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings (previously Williston Basin Interstate Pipeline Company, name changed effective July 1, 2012)
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Westmoreland	Westmoreland Coal Company
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
ZRC	Zonal resource credit - a MW of demand equivalent assigned to generators by MISO for meeting system reliability requirements

Part I

Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - MD&A - Prospective Information.

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

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

Items 1 and 2. Business and Properties

General

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

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

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (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 additional information, see Item 8 - Note 4.

As of December 31, 2013, the Company had 9,133 employees with 157 employed at MDU Resources Group, Inc., 1,010 at Montana-Dakota, 34 at Great Plains, 302 at Cascade, 219 at Intermountain, 583 at WBI Holdings, 3,071 at Knife River and 3,757 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, 2013.

At Montana-Dakota and WBI Energy Transmission, 350 and 77 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2015, and March 31, 2014, for Montana-Dakota and WBI Energy Transmission, respectively.

At Cascade, 173 employees are represented by the ICWU. The labor contract with the field operations group is effective through April 1, 2015.

At Intermountain, 116 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 approximately 520 of its construction materials employees. Knife River is in negotiations on 7 of its labor contracts.

MDU Construction Services has 176 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 134,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2013. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 10 electric

generating facilities and three small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,100 and 4,700 miles of transmission and distribution lines, respectively, and 52 transmission and 269 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, 2013, Montana-Dakota's net electric plant investment was $812.9 million.

The percentage of Montana-Dakota's 2013 retail electric utility operating revenues by jurisdiction is as follows: North Dakota - 62 percent; Montana - 22 percent; Wyoming - 10 percent; and South Dakota - 6 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 573,587 kW in July 2012. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the sales growth rate through 2018 will approximate 5 percent annually. The interconnected system consists of nine electric generating facilities and three small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 488,905 kW and total net ZRCs of 452.5 in 2013. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet supply obligations within MISO. For 2013, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 583.5. Montana-Dakota's peak demand supply obligation, including firm purchase power contracts, within MISO was 508.3 ZRCs for 2013. 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. Two 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 115 MW for the period June 1, 2013 to May 31, 2014, and 120 MW for the period June 1, 2014 to May 31, 2015. On October 25, 2013, Montana-Dakota entered into a power purchase agreement with Thunder Spirit Wind, LLC, a subsidiary of Wind Works Power Corp., for approximately 107 MW of installed capacity of wind turbine generators to be located in southwest North Dakota for a 25-year period effective on the commercial operation date of the facility. 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. Energy also will be purchased as needed, or if more economical, from the MISO market. In 2013, Montana-Dakota purchased approximately 29 percent of its net kWh needs for its interconnected system through the MISO market.

Montana-Dakota is constructing an 88-MW simple-cycle natural gas turbine and associated facilities, with an estimated project cost of $77 million and a projected in-service date in the third quarter 2014. The capacity is necessary to meet the requirements of Montana-Dakota's integrated electric system customers and will be a partial replacement for third-party contract capacity expiring in 2015. Advance determination of prudence and a Certificate of Public Convenience and Necessity have been received from the NDPSC for construction and operation of the natural gas turbine. A Certificate of Site Compatibility was issued for the turbine by the NDPSC on December 21, 2012.

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 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)	2013 ZRCs (a)	2013 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	101.7	666,431
Heskett	Steam	86,000	85.4	444,867
Glen Ullin	Heat Recovery	7,500	4.3	38,053
Cedar Hills	Wind	19,500	4.5	54,805
Diesel Units	Oil	5,475	5.6	6
South Dakota:				
Big Stone (b)	Steam	94,111	101.3	623,380
Montana:				
Lewis & Clark	Steam	44,000	52.1	298,969
Glendive	Combustion Turbine	75,522	72.9	1,782
Miles City	Combustion Turbine	23,150	19.5	—
Diamond Willow	Wind	30,000	5.2	93,175
		488,905	452.5	2,221,468
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	208,533
		516,905	452.5	2,430,001

(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.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland 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 2014, 1.0 million tons in 2015 and 500,000 tons in 2016 from Peabody Coalsales, LLC, and 500,000 tons in 2014 from Westmoreland 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., which provides for the purchase of coal necessary 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,	2013	2012	2011
Average cost of coal per MMBtu	$1.73	$1.69	$1.62
Average cost of coal per ton	$25.32	$24.77	$23.38

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 additional 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 additional information, see Item 8 - Note 6.

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 Coyote Station was submitted to the North Dakota Department of Health in March 2013 and the Title V Operating Permit renewal application for Big Stone Station was submitted to the South Dakota Department of Environment and Natural Resources in November 2013.

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 $32.7 million of environmental capital expenditures in 2013, largely for the installation of a BART air quality control system at the Big Stone Station. Capital expenditures are estimated to be $47 million, $46 million and $8 million in 2014, 2015 and 2016, 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 2014 through 2016 will also include sulfur-dioxide, nitrogen oxide and mercury and non-mercury metals control equipment installation at electric generating stations. 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 876,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states as of December 31, 2013, and provide natural gas transportation services to certain customers on their systems. These services are provided through distribution systems aggregating approximately 18,500 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, 2013, the natural gas distribution operations' net natural gas distribution plant investment was $1.1 billion.

The percentage of the natural gas distribution operations' 2013 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho - 34 percent; Washington - 24 percent; North Dakota - 14 percent; Oregon - 8 percent; Montana - 8 percent; South Dakota - 6 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. 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, Northwest Pipeline GP, Northern Natural Gas, Gas Transmission Northwest LLC, Northwestern Energy, Viking Gas Transmission Company and Ruby Pipeline LLC. 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 additional 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 2013. 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 2016.

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. Montana-Dakota will seek recovery through the MTPSC in its natural gas rates charged to customers for any remediation costs incurred for this site. 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, 2013, its net plant investment was $337.6 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. Total project costs are estimated to be approximately $350 million, with a projected in-service date in late 2014.

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, 2013, it has commitments to deliver fixed and determinable amounts of natural gas under these contracts of 1.9 MMdk in 2014 and the commitments to deliver natural gas for years subsequent to 2014 are immaterial. 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 2013 represented 45 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 a contract with WBI Energy Transmission to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements expiring in July 2015.

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.

Regulatory Matters For additional information on regulatory matters, see Item 8 - Note 18.

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 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 2013 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2016.

Exploration and Production
General Fidelity is involved in the acquisition, exploration, development and production of oil and natural gas resources. Fidelity continues to seek additional reserve and production growth opportunities through these activities. Future growth is dependent upon its success in these endeavors. 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 16,000 net acres in Mountrail County, North Dakota, approximately 50,000 net acres in Stark County, North Dakota, and approximately 59,000 net acres in Richland County, Montana.
- 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 130,000 net acres located in Grand and San Juan Counties, Utah, targeting oil, including its recent acquisition of 35,000 net acres of leaseholds and has an option to earn another 20,000 acres.
- Big Horn Basin - These interests include approximately 21,000 net acres in Wyoming, targeting oil and NGL.
- Green River Basin - These properties were primarily natural gas targets in Wyoming and were sold at the end of 2013.
- 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 exploratory 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 - This area includes approximately 9,000 net acres in the Tabasco, Texan Gardens and Flores fields. 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 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.

Annual net production by region for 2011 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total	
Rocky Mountain	2,290	199	34,472	8,234	74	%
Mid-Continent/Gulf States	434	577	11,126	2,865	26	
Total	2,724	776	45,598	11,099	100	%

Note: There are no fields that contain 15 percent or more of the Company's total proved reserves as of December 31, 2011.

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, 2013, were as follows:

	Gross *	Net **
Productive wells:		
Oil	899	171
Natural gas	2,006	1,541
Total	2,905	1,712
Developed acreage (000's)	581	347
Undeveloped acreage set to expire in the years (000's):		
2014	87	63
2015	130	81
2016	22	16
Thereafter	563	277
Total undeveloped acreage	802	437

* 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, 2013, Fidelity has commitments to deliver fixed and determinable amounts of oil under contracts of 452,500 Bbls in 2014 and the commitments to deliver oil for years subsequent to 2014 are immaterial. Fidelity does not have any material delivery commitments to deliver fixed and determinable amounts of natural gas at December 31, 2013.

Exploratory and Development Wells The following table reflects activities related to Fidelity's oil and natural gas wells drilled and/or tested during 2013, 2012 and 2011:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2013	3	2	5	35	3	38	43
2012	24	3	27	39	1	40	67
2011	4	—	4	48	—	48	52

At December 31, 2013, there were 11 gross (5 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 acquiring producing properties and new leases for future exploration and development, and in securing the equipment, services and expertise necessary to explore, 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 2013 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2016.

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 26 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, 2013. 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, 2013, are as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total	PV-10 Value * (in millions)
Rocky Mountain	38,788	2,442	128,124	62,584	78 %	$1,159.3
Mid-Continent/Gulf States	2,231	4,160	70,321	18,111	22	175.7
Total proved reserves	41,019	6,602	198,445	80,695	100 %	1,335.0
Discounted future income taxes						321.0
Standardized measure of discounted future net cash flows relating to proved reserves						$1,014.0

* 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 additional 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 $456 million in backlog at December 31, 2013, compared to $406 million at December 31, 2012. The Company anticipates that a significant amount of the current backlog will be completed during 2014.

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 private 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 2011 through 2013. 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, 2013, and sales for the years ended December 31, 2013, 2012 and 2011:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Production Area	owned	leased	owned	leased	2013	2012	2011			
Anchorage, AK	—	—	1	—	1,074	110	137	18,880	N/A	43
Hawaii	—	6	—	—	1,672	1,678	1,527	57,333	2017-2064	35
Northern CA	—	—	9	1	1,525	1,203	1,552	45,570	2018	32
Southern CA	—	2	—	—	241	784	1,134	92,110	2035	Over 100
Portland, OR	1	3	5	3	3,343	2,698	3,106	231,734	2014-2055	76
Eugene, OR	3	4	4	1	825	847	884	168,392	2016-2046	Over 100
Central OR/WA/ID	1	2	5	4	1,045	1,131	851	123,613	2015-2077	Over 100
Southwest OR	5	4	11	5	1,465	1,613	1,604	96,768	2014-2053	62
Central MT	—	—	1	2	1,236	1,200	758	28,213	2017-2027	26
Northwest MT	—	—	7	2	1,242	1,011	1,370	65,993	2016-2020	55
Wyoming	—	—	1	1	983	428	461	11,571	2019	19
Central MN	—	1	37	24	1,578	1,714	1,520	73,429	2014-2028	46
Northern MN	2	—	16	5	349	195	355	26,782	2015-2017	89
ND/SD	—	—	3	19	1,862	1,711	1,727	30,899	2014-2031	17
Iowa	—	—	—	—	—	305	249	—	—	—
Texas	1	1	1	—	672	692	1,182	12,089	2022	14
Sales from other sources					5,601	5,965	6,319			
					24,713	23,285	24,736	1,083,376		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2013, are comprised of 494 million tons that are owned and 589 million tons that are leased. Approximately 49 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 28 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2011 through 2013 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 68 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:

	2013	2012	2011
	(000's of tons)		
Aggregate reserves:			
Beginning of year	1,088,236	1,088,833	1,107,396
Acquisitions	22,682	950	1,200
Sales volumes*	(19,112)	(17,320)	(18,417)
Other**	(8,430)	15,773	(1,346)
End of year	1,083,376	1,088,236	1,088,833

* 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 SMCRA, 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 with all final bond release applications being filed by 2016.

Knife River did not incur any material environmental expenditures in 2013 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 2016.

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 additional information, see Item 8 - Note 19.

Mine Safety The Dodd-Frank Act requires disclosure of certain mine safety information. For additional 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, 2013, MDU Construction Services owned or leased facilities in 16 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, 2013, was approximately $459 million compared to $325 million at December 31, 2012. MDU Construction Services expects to complete a significant amount of this backlog during 2014. 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 2013 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2016.

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; availability of economic supplies of natural gas; drilling successes in oil and natural gas operations; the timely receipt of necessary permits and approvals; the ability to contract for or to secure necessary drilling rig and service contracts and to retain employees to identify, drill for and develop reserves; the ability to acquire oil and natural gas properties; and other risks incidental to the development and operations of oil and natural gas wells, processing plants and pipeline systems. Volatility in oil, NGL and natural gas prices 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.

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

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

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 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. 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 both short-term borrowings, including the issuance of commercial paper, and long-term capital markets 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 issued, 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, including the current economic slowdown. Accordingly, there is no assurance that backlog will be realized.

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 downward movements in prices, could result in additional 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. There is risk that lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in additional future noncash write-downs of the Company's oil and natural gas properties.

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 present and future operations, including air quality, water quality, waste management and other environmental considerations. These laws and regulations can result in increased capital, operating and other costs, cause delays as a result of litigation and administrative proceedings, and create compliance, remediation, containment, monitoring and reporting obligations, particularly with regard to laws relating to electric generation operations and oil and natural gas development 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, as well as private individuals, may seek injunctive relief or other remedies to enforce applicable environmental laws and regulations with which they have differing interpretations of the Company's legal or regulatory compliance. The Company cannot predict the outcome (financial or operational) of any related litigation or administrative proceedings that may arise.

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

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

In December 2011, the EPA finalized the Mercury and Air Toxics 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 final rule and determined that additional particulate matter control is required to control non-mercury metal emissions at the Lewis & Clark Station near Sidney, Montana. On October 9, 2013, Montana-Dakota received an order from the NDPSC approving Montana-Dakota's request for advance determination of prudence to install a baghouse at Lewis & Clark Station. Controls must be installed by April 16, 2015, or April 16, 2016, if a one-year extension is granted for installation.

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

On August 16, 2012, the EPA published a final NSPS rule for the oil and natural gas industry. The NSPS rule phases in over two years. The first phase was effective October 15, 2012, and primarily covers natural gas wells that are hydraulically fractured. Under the new rule, gas vapors or emissions from the natural gas wells must be captured or combusted utilizing a high efficiency device. Additional reporting requirements and control devices covering oil and natural gas production equipment will be phased in for certain new oil and gas facilities with a final effective date of January 1, 2015. This new rule's impacts on Fidelity, WBI Energy Transmission and WBI Energy Midstream are not expected to be material and are likely to include implementation of recordkeeping, reporting and testing requirements and the acquisition and installation of required equipment.

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

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. On June 25, 2013, President Obama released his Climate Action Plan for the U.S. in which he 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 for any new coal-fired electric generation to be constructed unless carbon dioxide is captured and sequestered. The EPA has not applied this new standard to existing fossil fuel-fired units or existing units that make modifications, therefore no impacts to Montana-Dakota's existing electric generating facilities are expected. However, it is not clear that the EPA will always exempt required future pollution control project modifications from GHG NSPS. If the EPA does not clearly exempt these projects, the Company's electric generation operations could be adversely impacted.

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

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

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

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

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

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 multiemployer pension plans 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 80 multiemployer pension plans 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 45 percent of the multiemployer plans to which it contributes are currently in endangered, seriously endangered or critical status.

The Company may also be required to increase its contributions to multiemployer plans 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 multiemployer pension plans 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 multiemployer pension plans, 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.

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 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. 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 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, remediation costs and possible legal claims and fines which could adversely affect the Company's financial results. 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.

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.

Part II

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

The Company's common stock is listed on the New York Stock Exchange under the symbol "MDU." The price range of the Company's common stock as reported by The Wall Street Journal composite tape during 2013 and 2012 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
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
2012			
First quarter	$22.50	$21.14	$.1675
Second quarter	23.21	20.76	.1675
Third quarter	23.11	21.42	.1675
Fourth quarter	22.23	19.59	.1725
			$.6750

As of December 31, 2013, the Company's common stock was held by approximately 13,900 stockholders of record.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends, see Item 8 - Note 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, 2013	—			
November 1 through November 30, 2013	33,027	$30.53		
	3,686	29.83		

December 1 through December 31, 2013	
Total	36,713

(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.

30

Item 6. Selected Financial Data

	2013	2012 (a)	2011	2010	2009 (b)	2008 (c)
Selected Financial Data						
Operating revenues (000's):						
Electric	$257,260	$236,895	$225,468	$211,544	$196,171	$208,326
Natural gas distribution	851,945	754,848	907,400	892,708	1,072,776	1,036,109
Pipeline and energy services	202,068	193,157	278,343	329,809	307,827	532,153
Exploration and production	536,023	448,617	453,586	434,354	439,655	712,279
Construction materials and contracting	1,712,137	1,617,425	1,510,010	1,445,148	1,515,122	1,640,683
Construction services	1,039,839	938,558	854,389	789,100	819,064	1,257,319
Other	9,620	10,370	11,446	7,727	9,487	10,501
Intersegment eliminations	(146,488)	(124,439)	(190,150)	(200,695)	(183,601)	(394,092)
	$4,462,404	$4,075,431	$4,050,492	$3,909,695	$4,176,501	$5,003,278
Operating income (loss) (000's):						
Electric	$54,274	$49,852	$49,096	$48,296	$36,709	$35,415
Natural gas distribution	78,829	67,579	82,856	75,697	76,899	76,887
Pipeline and energy services	20,046	49,139	45,365	46,310	69,388	49,560
Exploration and production	161,402	(276,642)	133,790	143,169	(473,399)	202,954
Construction materials and contracting	93,629	57,864	51,092	63,045	93,270	62,849
Construction services	85,246	66,531	39,144	33,352	44,255	81,485
Other	6,649	4,884	5,024	858	(219)	2,887
Intersegment eliminations	(7,176)	—	—	—	—	—
	$492,899	$19,207	$406,367	$410,727	$(153,097)	$512,037
Earnings (loss) on common stock (000's):						
Electric	$34,837	$30,634	$29,258	$28,908	$24,099	$18,755
Natural gas distribution	37,656	29,409	38,398	36,944	30,796	34,774
Pipeline and energy services	7,629	26,588	23,082	23,208	37,845	26,367
Exploration and production	94,450	(177,283)	80,282	85,638	(296,730)	122,326
Construction materials and contracting	50,946	32,420	26,430	29,609	47,085	30,172
Construction services	52,213	38,429	21,627	17,982	25,589	49,782
Other	5,136	4,797	6,190	21,046	7,357	10,812
Intersegment eliminations	(4,307)	—	—	—	—	—
Earnings (loss) on common stock before income (loss) from discontinued operations	278,560	(15,006)	225,267	243,335	(123,959)	292,988

Income (loss) from discontinued operations, net of tax	(312)	13,567	(12,926)	(3,361)	—	—
	$278,248	$(1,439)	$212,341	$239,974	$(123,959)	$292,988
Earnings (loss) per common share before discontinued operations - diluted	$1.47	$(.08)	$1.19	$1.29	$(.67)	$1.59
Discontinued operations, net of tax	—	.07	(.07)	(.02)	—	—
	$1.47	$(.01)	$1.12	$1.27	$(.67)	$1.59

31

	2013	2012 (a)	2011	2010	2009 (b)	2008 (c)
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	189,693	188,826	188,905	188,229	185,175	183,807
Dividends declared per common share	$ .6950	$ .6750	$ .6550	$ .6350	$ .6225	$ .6000
Book value per common share	$ 15.01	$ 13.95	$ 14.62	$ 14.22	$ 13.61	$ 14.95
Market price per common share (year end)	$ 30.55	$ 21.24	$ 21.46	$ 20.27	$ 23.60	$ 21.58
Market price ratios:						
Dividend payout	47 %	(d)	58 %	50 %	(d)	38 %
Yield	2.3 %	3.2 %	3.1 %	3.2 %	2.7 %	2.9 %
Market value as a percent of book value	203.5 %	152.3 %	146.8 %	142.5 %	173.4 %	144.3 %

(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) Reflects an $84.2 million after-tax noncash write-down of oil and natural gas properties.
(d) Not meaningful due to effects of the after-tax noncash write-down(s), as previously discussed.
Note: Intermountain, a natural gas distribution business, was acquired on October 1, 2008.

32

	2013	2012	2011	2010	2009	2008
General						
Total assets (000's)	$7,061,332	$6,682,491	$6,556,125	$6,303,549	$5,990,952	$6,587,845
Total long-term debt (000's)	$1,854,563	$1,744,975	$1,424,678	$1,506,752	$1,499,306	$1,647,302
Capitalization ratios:						
Common equity	60 %	60 %	66 %	64 %	63 %	61 %
Total debt	40	40	34	36	37	39
	100 %	100 %	100 %	100 %	100 %	100 %
Electric						
Retail sales (thousand kWh)	3,173,086	2,996,528	2,878,852	2,785,710	2,663,560	2,663,452
Electric system summer and firm purchase contract ZRCs (Interconnected system)	583.5	552.8	572.8	553.3	(a)	(a)
Electric system peak demand obligation, including firm purchase contracts, ZRCs (Interconnected system)	508.3	550.7	524.2	529.5	(a)	(a)
Demand peak - kW (Interconnected system)	573,587	573,587	535,761	525,643	525,643	525,643
Electricity produced (thousand kWh)	2,430,001	2,299,686	2,488,337	2,472,288	2,203,665	2,538,439
Electricity purchased (thousand kWh)	971,261	870,516	645,567	521,156	682,152	516,654
Average cost of fuel and purchased power per kWh	$.025	$.023	$.021	$.021	$.023	$.025
Natural Gas Distribution (b)						
Sales (Mdk)	108,260	93,810	103,237	95,480	102,670	87,924
Transportation (Mdk)	149,490	132,010	124,227	135,823	132,689	103,504
Degree days (% of normal)						
Montana-Dakota/Great Plains	105 %	84 %	101 %	98 %	104 %	103 %
Cascade	98 %	96 %	103 %	96 %	105 %	108 %
Intermountain	110 %	91 %	107 %	100 %	107 %	90 %
Pipeline and Energy Services						
Transportation (Mdk)	178,598	137,720	113,217	140,528	163,283	138,003
Gathering (Mdk)	40,737	47,084	66,500	77,154	92,598	102,064
Customer natural gas storage balance (Mdk)	26,693	43,731	36,021	58,784	61,506	30,598
Exploration and Production						
Production:						
Oil (MBbls)	4,815	3,694	2,724	2,767	2,557	2,232
NGL (MBbls)	781	828	776	495	554	576
Natural gas (MMcf)	28,008	33,214	45,598	50,391	56,632	65,457
Total production (MBOE)	10,264	10,058	11,099	11,661	12,550	13,717
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):						
Oil (per Bbl)	$89.70	$84.84	$91.62	$70.61	$53.57	$89.41
NGL (per Bbl)	$37.39	$39.81	$54.06	$44.93	$32.18	$54.65

Natural gas (per Mcf)	$2.89	$2.08	$3.30	$3.57	$2.99	$7.29
Average realized prices (including realized gain/loss on commodity derivatives):						
Oil (per Bbl)	$89.35	$86.54	$86.20	$69.59	$50.67	$88.66
NGL (per Bbl)	$37.39	$39.81	$54.06	$44.93	$32.18	$54.65
Natural gas (per Mcf)	$2.96	$2.91	$3.84	$4.36	$5.16	$7.38
Proved reserves:						
Oil (MBbls)	41,019	33,453	27,005	25,666	25,930	25,238
NGL (MBbls)	6,602	7,153	7,342	7,201	8,286	9,110
Natural gas (MMcf)	198,445	239,278	379,827	448,397	448,425	604,282
Total proved reserves (MBOE)	80,695	80,486	97,651	107,599	108,954	135,062

	2013	2012	2011	2010	2009	2008
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	24,713	23,285	24,736	23,349	23,995	31,107
Asphalt (tons)	6,228	5,988	6,709	6,279	6,360	5,846
Ready-mixed concrete (cubic yards)	3,223	3,157	2,864	2,764	3,042	3,729
Aggregate reserves (000's tons)	1,083,376	1,088,236	1,088,833	1,107,396	1,125,491	1,145,161

(a) Information not available for periods prior to 2010.
(b) Intermountain was acquired on October 1, 2008.

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

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities, revolving credit facilities and the issuance from time to time of debt and equity securities. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments.

The key strategies for each of the Company's business segments and certain related business challenges are summarized below. For a summary of the Company's business segments, see 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 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; natural gas basis differentials; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other pipeline and energy services companies.

Exploration and Production

Strategy Apply technology and utilize existing exploration and production expertise, with a focus on operated properties, to increase production and reserves from existing leaseholds, and to seek additional reserves and production opportunities both in new and existing areas to further expand the segment's asset base. By optimizing existing operations and taking advantage of new and incremental growth opportunities, this segment is focused on balancing the oil and natural gas commodity mix to maximize profitability with its goal to add value by increasing both reserves and production over the long term so as to generate competitive returns on investment.

Challenges Volatility in natural gas and oil prices; timely receipt of necessary permits and approvals; environmental and regulatory requirements; recruitment and retention of a skilled workforce; availability of drilling rigs, materials, auxiliary equipment and industry-related field services; inflationary pressure on development and operating costs; and competition from other exploration and production companies are ongoing challenges for this segment.

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

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

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

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

For more information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see Item 1A - Risk Factors. For more information on each segment's key growth strategies, projections and certain assumptions, see Prospective Information.

For information pertinent to various commitments and contingencies, see 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,	2013	2012	2011
	(Dollars in millions, where applicable)		
Electric	$34.8	$30.6	$29.2
Natural gas distribution	37.7	29.4	38.4
Pipeline and energy services	7.6	26.6	23.1
Exploration and production	94.5	(177.2)	80.3
Construction materials and contracting	50.9	32.4	26.4
Construction services	52.2	38.4	21.6
Other	5.1	4.8	6.2
Intersegment eliminations	(4.3)	—	—
Earnings (loss) before discontinued operations	278.5	(15.0)	225.2
Income (loss) from discontinued operations, net of tax	(.3)	13.6	(12.9)
Earnings (loss) on common stock	$278.2	$(1.4)	$212.3
Earnings (loss) per common share - basic:			
Earnings (loss) before discontinued operations	$1.47	$(.08)	$1.19
Discontinued operations, net of tax	—	.07	(.07)
Earnings (loss) per common share - basic	$1.47	$(.01)	$1.12
Earnings (loss) per common share - diluted:			
Earnings (loss) before discontinued operations	$1.47	$(.08)	$1.19
Discontinued operations, net of tax	—	.07	(.07)
Earnings (loss) per common share - diluted	$1.47	$(.01)	$1.12

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 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

2012 compared to 2011 Consolidated earnings for 2012 decreased $213.7 million from the prior year. This decrease was due to:

- Noncash write-downs of oil and natural gas properties of $246.8 million (after tax), lower average realized natural gas prices, decreased natural gas production, as well as higher depreciation, depletion and amortization expense, partially offset by increased oil production at the exploration and production business
- Decreased retail sales volumes at the natural gas distribution business, largely resulting from warmer weather than last year

Partially offsetting these decreases were:

- Income from discontinued operations of $13.6 million (after tax), largely related to a benefit from an arbitration charge reversal resulting from a favorable court ruling, as discussed in Item 8 - Note 3
- Higher workloads and margins in the Central and Western regions, higher equipment sales and rental margins, as well as higher margins in the Mountain region, partially offset by higher general and administrative expense at the construction services business
- Higher ready-mixed concrete and other product line margins and volumes, increased construction margins, as well as higher liquid asphalt oil margins and volumes, partially offset by lower gains from the sale of property, plant and equipment and lower aggregate and asphalt margins and volumes at the construction materials and contracting business
- Lower operation and maintenance expense from existing operations largely related to a $15.0 million (after tax) net benefit related to the natural gas gathering operations litigation, as discussed in Item 8 - Note 19, partially offset by lower natural gas gathering volumes from existing operations at the pipeline and energy services business

Financial and Operating Data

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

Electric

Years ended December 31,	2013	2012	2011
	(Dollars in millions, where applicable)		
Operating revenues	$257.3	$236.9	$225.5
Operating expenses:			
Fuel and purchased power	83.5	72.4	64.5
Operation and maintenance	76.5	71.8	70.3
Depreciation, depletion and amortization	32.8	32.5	32.2
Taxes, other than income	10.2	10.3	9.4
	203.0	187.0	176.4
Operating income	54.3	49.9	49.1
Earnings	$34.8	$30.6	$29.2
Retail sales (million kWh)	3,173.1	2,996.5	2,878.9
Average cost of fuel and purchased power per kWh	$.025	$.023	$.021

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.

2012 compared to 2011 Electric earnings increased $1.4 million (5 percent) compared to the prior year due to:

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Higher retail sales volumes of 4 percent, primarily to small commercial and industrial and residential customers, reflecting increased demand due to warmer summer weather than last year, as well as increased customer growth, offset in part by decreased volumes to large commercial and industrial customers

- Higher other income, largely higher allowance for funds used during construction of $900,000 (after tax)
- Lower net interest expense, which includes $900,000 (after tax) due in part to higher capitalized interest

Partially offsetting these increases were:

- Higher income taxes, including $1.4 million which is partially related to the absence of an income tax benefit related to favorable resolutions of certain income tax matters in 2011
- Increased taxes other than income of $600,000 (after tax), primarily related to higher property taxes

- Higher operation and maintenance expense, which includes $500,000 (after tax) largely related to increased contract services at certain of the Company's electric generation stations, as well as higher payroll-related costs, partially offset by lower benefit-related costs

Natural Gas Distribution

Years ended December 31,	2013	2012	2011
	(Dollars in millions, where applicable)		
Operating revenues	$851.9	$754.8	$907.4
Operating expenses:			
Purchased natural gas sold	534.8	457.4	594.6
Operation and maintenance	142.3	139.4	137.3
Depreciation, depletion and amortization	50.0	45.7	44.6
Taxes, other than income	46.0	44.7	48.0
	773.1	687.2	824.5
Operating income	78.8	67.6	82.9
Earnings	$37.7	$29.4	$38.4
Volumes (MMdk):			
Sales	108.3	93.8	103.3
Transportation	149.5	132.0	124.2
Total throughput	257.8	225.8	227.5
Degree days (% of normal)*			
Montana-Dakota/Great Plains	105%	84%	101%
Cascade	98%	96%	103%
Intermountain	110%	91%	107%
Average cost of natural gas, including transportation, per dk	$4.94	$4.88	$5.76

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

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

2012 compared to 2011 The natural gas distribution business experienced a decrease in earnings of $9.0 million (23 percent) compared to the prior year due to:

- Lower earnings of $7.6 million (after tax) related to decreased retail sales volumes, largely resulting from warmer weather than last year, partially offset by weather normalization in certain jurisdictions

- Taxes other than income includes $1.3 million (after tax) primarily related to higher property taxes. Taxes other than income also reflects the effect of lower natural gas revenues.
- Absence in 2012 of a reduction of deferred income taxes, which includes $1.2 million primarily associated with benefits in 2011
- Increased operation and maintenance expense, which includes $700,000 (after tax) partially related to increased contract services

These decreases were partially offset by higher other income, which includes $1.1 million (after tax) primarily related to allowance for funds used during construction.

Pipeline and Energy Services

Years ended December 31,	2013	2012	2011
	(Dollars in millions)		
Operating revenues	$202.1	$193.1	$278.3
Operating expenses:			
Purchased natural gas sold	57.5	50.5	125.3
Operation and maintenance*	81.8	52.2	68.9
Depreciation, depletion and amortization	29.1	27.7	25.5
Taxes, other than income	13.6	13.6	13.2
	182.0	144.0	232.9
Operating income	20.1	49.1	45.4
Earnings*	$7.6	$26.6	$23.1
Transportation volumes (MMdk)	178.6	137.7	113.2
Natural gas gathering volumes (MMdk)	40.7	47.1	66.5
Customer natural gas storage balance (MMdk):			
Beginning of period	43.7	36.0	58.8
Net injection (withdrawal)	(17.0)	7.7	(22.8)
End of period	26.7	43.7	36.0

* 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.

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

2012 compared to 2011 Pipeline and energy services earnings increased $3.5 million (15 percent) largely due to:

- Lower operation and maintenance expense from existing operations largely related to a $15.0 million (after tax) net benefit related to the natural gas gathering operations litigation, as discussed in Item 8 - Note 19, which was partially offset by an impairment of certain natural gas gathering assets of $1.7 million (after tax) due largely to low natural gas prices
- Higher oil and natural gas gathering and processing volumes from the acquisition of the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, as discussed in Item 8 - Note 2

Partially offsetting the earnings increase were:

- Lower earnings of $10.4 million (after tax) due to lower natural gas gathering volumes from existing operations, largely resulting from customers experiencing normal declines, production curtailments, deferral of certain natural gas development activity and the Company's divestments
- Lower storage services revenue of $600,000 (after tax), largely lower average storage balances, as well as lower withdrawal volumes

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

Exploration and Production

Years ended December 31,	2013	2012	2011
	(Dollars in millions, where applicable)		
Operating revenues:			
Oil	$431.9	$313.4	$249.6
NGL	29.2	33.0	41.9
Natural gas	81.0	69.2	150.7
Realized gain on commodity derivatives	.2	33.6	9.6
Unrealized gain (loss) on commodity derivatives	(6.3)	(.6)	1.8
	536.0	448.6	453.6
Operating expenses:			
Operation and maintenance:			
Lease operating costs	82.2	77.7	75.6
Gathering and transportation	15.4	17.4	24.3
Other	42.9	37.0	36.5
Depreciation, depletion and amortization	186.4	160.7	142.6
Taxes, other than income:			
Production and property taxes	46.6	39.7	40.8
Other	1.1	1.0	—
Write-downs of oil and natural gas properties	—	391.8	—
	374.6	725.3	319.8
Operating income (loss)	161.4	(276.7)	133.8
Earnings (loss)	$94.5	$(177.2)	$80.3
Production:			
Oil (MBbls)	4,815	3,694	2,724
NGL (MBbls)	781	828	776
Natural gas (MMcf)	28,008	33,214	45,598
Total production (MBOE)	10,264	10,058	11,099
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):			
Oil (per Bbl)	$89.70	$84.84	$91.62
NGL (per Bbl)	$37.39	$39.81	$54.06
Natural gas (per Mcf)	$2.89	$2.08	$3.30
Average realized prices (including realized gain/loss on commodity derivatives):			
Oil (per Bbl)	$89.35	$86.54	$86.20
NGL (per Bbl)	$37.39	$39.81	$54.06
Natural gas (per Mcf)	$2.96	$2.91	$3.84

Average depreciation, depletion and amortization rate, per BOE	$17.41	$15.28	$12.25
Production costs, including taxes, per BOE:			
Lease operating costs	$8.01	$7.73	$6.81
Gathering and transportation	1.50	1.73	2.19
Production and property taxes	4.54	3.94	3.67
	$14.05	$13.40	$12.67

41

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

2012 compared to 2011 Earnings at the exploration and production business decreased $257.5 million due to:

- Noncash write-downs of oil and natural gas properties of $246.8 million (after tax), as discussed in Item 8 - Note 1
- Lower average realized natural gas prices of 25 percent
- Decreased natural gas production of 27 percent, largely related to normal declines, production curtailments, deferral of certain natural gas development activity and divestment of existing properties
- Higher depreciation, depletion and amortization expense of $11.4 million (after tax), due to higher depletion rates, partially offset by lower volumes
- Lower average realized NGL prices of 26 percent

Partially offsetting these decreases were:

- Increased oil production of 36 percent, primarily related to drilling activity in the Bakken area, as well as the Paradox Basin
- Lower gathering and transportation expense of $4.3 million (after tax), largely due to lower gathering costs resulting from lower volumes and lower gathering rates in the coalbed area

Construction Materials and Contracting

Years ended December 31,	2013	2012	2011
	(Dollars in millions)		
Operating revenues	$1,712.1	$1,617.4	$1,510.0
Operating expenses:			
Operation and maintenance	1,505.2	1,442.5	1,337.4

Depreciation, depletion and amortization	74.5	79.5	85.5
Taxes, other than income	38.8	37.5	36.0
	1,618.5	1,559.5	1,458.9
Operating income	93.6	57.9	51.1
Earnings	$50.9	$32.4	$26.4
Sales (000's):			
Aggregates (tons)	24,713	23,285	24,736
Asphalt (tons)	6,228	5,988	6,709
Ready-mixed concrete (cubic yards)	3,223	3,157	2,864

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

2012 compared to 2011 Earnings at the construction materials and contracting business increased $6.0 million (23 percent) due to:

- Higher earnings of $6.4 million (after tax) resulting from higher ready-mixed concrete margins and volumes, primarily in the North Central and Northwest regions, as well as higher other product line volumes and margins
- Increased construction margins of $3.6 million (after tax), largely related to increased construction margins in the South and Intermountain regions
- Higher earnings of $3.6 million (after tax) resulting from higher liquid asphalt oil margins and volumes
- Lower selling, general and administrative costs of $2.8 million (after tax), largely due to lower benefit and payroll-related costs

Partially offsetting the increases were:

- Lower gains of $4.0 million (after tax) from the sale of property, plant and equipment
- Lower earnings of $3.6 million (after tax) resulting from lower aggregate margins primarily due to higher costs, as well as lower volumes
- Lower earnings of $2.9 million (after tax) resulting from lower asphalt margins primarily due to higher costs, as well as lower volumes

Construction Services

Years ended December 31,	2013	2012	2011
	(In millions)		
Operating revenues	$1,039.8	$938.6	$854.4
Operating expenses:			
Operation and maintenance	910.7	831.9	778.5
Depreciation, depletion and amortization	11.9	11.1	11.4
Taxes, other than income	32.0	29.1	25.4
	954.6	872.1	815.3
Operating income	85.2	66.5	39.1
Earnings	$52.2	$38.4	$21.6

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.

2012 compared to 2011 Construction services earnings increased $16.8 million (78 percent) compared to the prior year due to higher earnings of $21.3 million resulting from higher workloads and margins in the Central and Western regions, higher equipment sales and rental margins, as well as higher margins in the Mountain region. These increases were partially offset by higher general and administrative expense of $4.6 million (after tax), including higher payroll-related costs.

Other

Years ended December 31,	2013	2012	2011
	(In millions)		
Operating revenues	$9.6	$10.4	$11.4
Operating expenses:			
Operation and maintenance	.8	3.3	4.7
Depreciation, depletion and amortization	2.1	2.0	1.6
Taxes, other than income	.1	.2	.1
	3.0	5.5	6.4
Operating income	6.6	4.9	5.0
Income from continuing operations	5.1	4.8	6.2
Income (loss) from discontinued operations, net of tax	(.3)	13.6	(12.9)
Earnings (loss)	$4.8	$18.4	$(6.7)

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.

2012 compared to 2011 Other earnings increased $25.1 million compared to the prior year primarily due to income from discontinued operations of $13.6 million (after tax) in 2012, largely the net benefit related to the reversal of an arbitration charge, as previously discussed, compared to a loss from discontinued operations of $12.9 million (after tax) in 2011, largely related to the 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,	2013	2012	2011
	(In millions)		
Intersegment transactions:			
Operating revenues	$146.4	$124.4	$190.1
Purchased natural gas sold	87.2	82.7	147.7
Operation and maintenance	52.1	41.7	42.4
Income taxes	2.8	—	—
Earnings on common stock	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.

- Adjusted earnings per common share for 2014 are projected in the range of $1.45 to $1.60. GAAP earnings guidance for 2014 is in the same range. Unrealized commodity derivatives fair values can fluctuate causing actual GAAP earnings to vary accordingly.

- The Company's long-term compound annual growth goals on earnings per common 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. For example, the pipeline and energy services business' Dakota Prairie Refinery has the construction materials and services business involved in constructing the facility, the exploration and production business supplying production, either directly or in kind, to the plant, the pipeline transporting natural gas to the plant and the utility supplying electricity.

Electric and natural gas distribution

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

- Regulatory actions

The Company filed an application September 18, 2013, with the NDPSC for a natural gas rate increase, as discussed in Item 8 - Note 18.

The Company filed an application June 14, 2013, for an advance determination of prudence with the NDPSC to add pollution control equipment at the Lewis & Clark generating station projected to be completed in 2016 to comply with the Mercury and Air Toxics Standards rules. On October 9, 2013, the commission issued an order approving the advance determination of prudence.

The Company filed an application February 11, 2013, with the NDPSC for approval of an environmental cost recovery rider related to ongoing construction costs at the Big Stone Station for the installation of the BART air-quality control system, as discussed in Item 8 - Note 18.

The Company filed an application December 21, 2012, with the SDPUC for a natural gas rate increase requesting a total of $1.5 million annually or approximately 3.3 percent above current rates. The case includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, an operations building, automated meter reading and new customer billing system. The Company implemented the full request July 22, 2013, subject to refund. On November 5, 2013, the commission approved a settlement stipulation for an increase of $900,000 annually, or 2.0 percent, effective with service rendered December 1, 2013.

The Company filed an application September 26, 2012, with the MTPSC for a natural gas rate increase, as discussed in Item 8 - Note 18.

Effective November 1, 2013, the WUTC approved recovery of $1.0 million over a one-year period for qualifying pipeline replacement projects. The WUTC issued a policy statement dated December 31, 2012, related to the accelerated replacement of natural gas pipeline facilities.

- The Company is constructing an 88-MW simple-cycle natural gas turbine and associated facilities, with an estimated project cost of $77 million and a projected in-service date in third quarter 2014. It is located on owned property adjacent to the Company's Heskett Generating Station near Mandan, North Dakota. The capacity is necessary to meet the requirements of the Company's integrated electric system customers and will be a partial replacement for third-party contract capacity expiring in 2015. Advance determination of prudence and a Certificate of Public Convenience and Necessity have been received from the NDPSC.

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Investments are being made in 2014 totaling approximately $70 million to serve the growing electric and natural gas customer base associated with the Bakken oil development where customer growth is substantially higher than the national average.

- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors, with company- and customer-owned pipeline facilities designed to serve existing facilities served by fuel oil or propane, and to serve new customers. The Company is engaged 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, at a total cost of approximately $360 million. The Company's share would be one-half. 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. The project is expected to be complete in 2019.

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

Pipeline and energy services

- In January 2014, the Company launched an open season to obtain capacity commitments on a proposed 375-mile natural gas pipeline from western North Dakota to northwestern Minnesota to transport natural gas to markets in eastern North Dakota, Minnesota, Wisconsin, Michigan and other Midwest markets. The pipeline is expected to provide access to additional markets via interconnections with pipelines owned by Great Lakes Gas Transmission, Viking Gas Transmission and potentially TransCanada, in northwestern Minnesota. An interconnection with the Alliance Pipeline system in eastern North Dakota also is possible. Initially the pipeline would transport approximately 400 MMcf per day of natural gas and could be expanded to more than 500 MMcf per day. The project investment is estimated to be approximately $650 million. Following the open season, receipt of adequate capacity commitments and necessary permits and regulatory approvals, construction on the new pipeline could begin in 2016 with completion expected in 2017.

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

- On October 31, 2013, WBI Energy Transmission filed a Section 4 rate case with the FERC, as discussed in Item 8 - Note 18.

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

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

Exploration and production

- The Company expects to spend approximately $440 million in capital expenditures in 2014.

- For 2014, the Company expects a 10 to 20 percent increase in oil production and a 5 to 10 percent increase in NGL production. Natural gas production is expected to decline 20 to 30 percent compared to a year ago, primarily the result of the divestment of certain non-strategic natural gas-based properties in 2013. The vast majority of the capital program is focused on growing oil production considering current relative commodity prices. The Company expects to return to some natural gas development when the commodity prices make it more profitable to do so.

- The Company has a total of four drilling rigs deployed on its acreage in the Bakken and Paradox Basin areas, with two rigs operating in each area.

- Bakken areas

The Company owns a total of approximately 125,000 net acres of leaseholds in Mountrail and Stark counties, North Dakota and Richland County, Montana. The Middle Bakken and Three Forks formations are targeted in North Dakota and the Red River formation is targeted in Montana.

Capital expenditures are expected to total approximately $130 million in 2014.

Net oil production for the fourth quarter 2013 was approximately 7,900 BOPD which is down 5 percent from third quarter 2013. This quarter-on-quarter drop in oil production was primarily driven by weather-related downtime in December 2013, as well as delay of a three-well pad completion.

Alternative completion techniques, including increased stage count and cemented liners in the Middle Bakken (Mountrail County) and Three Forks (Mountrail and Stark counties) are being tested, with completion design changes to be finalized later in 2014.

- Paradox Basin, Utah

The Company owns approximately 130,000 net acres of leaseholds including its recent acquisition of 35,000 net acres of leaseholds and has an option to earn another 20,000 acres. The Company expects to further expand its acreage in the basin.

Capital expenditures are expected to total approximately $170 million in 2014.

Well costs have increased and now range from $10 million to $11 million per well driven by increased lateral lengths. With longer lateral lengths, estimated ultimate recoveries are expected to increase with the upper range now at 1.5 MMBbls of oil per well.

Following nine months of flowing at a constant 1,500 BOPD gross, the CCU 12-1 well came off its plateau rate and for the past seven months has still been flowing at approximately 1,000 BOPD. Cumulative production is 600 MBbls of oil.

Net oil production for fourth quarter 2013 was approximately 2,850 BOPD, up 89 percent from fourth quarter 2012 and 24 percent higher than third quarter 2013. Current production is approximately 3,000 BOPD.

The CCU 7-1 well has just been completed and is in the initial flowback and production ramp up period. Flowing on a 5/64 choke, the well was producing 350 BOPD at more than 3,000 psi flowing pressure. The well will be brought to full production capability over the next month. The CCU 36-1 has been flowing consistently at an average rate of 930 BOPD gross since October 11, 2013, with an average flowing pressure of approximately 3,400 psi.

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

- Other opportunities

The Company has continued its focus on adding a third oil play and on February 10, 2014, entered into an agreement to purchase working interests and leasehold positions in oil and natural gas production assets in the southern Powder River Basin of Wyoming. Current net production is more than 1,100 BOE per day, 80 percent of which is oil, with additional production expected to be on line before closing. For more information, see Item 8 - Note 20.

- Earnings guidance reflects estimated average NYMEX index prices for February through December 2014 in the range of $90 to $95 per Bbl of crude oil and $3.75 to $4.25 per Mcf of natural gas. Estimated prices for NGL are in the range of $35 to $45 per Bbl.

- Derivatives

The Company has derivative instruments for 11,000 BOPD for the first six months of 2014, 10,000 BOPD for July through September 2014 and 5,000 BOPD for October through December 2014, utilizing swaps with a weighted average price of $94.90. Covering full-year 2014, the Company has derivative instruments for 40,000 MMBtu of natural gas per day utilizing swaps at a weighted average price of $4.10.

For 2015, the Company has a derivative instrument for 10,000 MMBtu of natural gas per day utilizing a swap at $4.28.

The commodity derivative instruments that are in place as of February 18, 2014, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (Bbl/MMBtu)	Price (Per Bbl/MMBtu)
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$95.15
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$95.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$90.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$91.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$92.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$93.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$98.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$99.00
Crude Oil	Swap	NYMEX	1/14 - 6/14	181,000	$100.07
Crude Oil	Swap	NYMEX	1/14 - 12/14	365,000	$94.05
Crude Oil	Swap	NYMEX	1/14 - 12/14	365,000	$95.00
Crude Oil	Swap	NYMEX	7/14 - 9/14	184,000	$95.75
Crude Oil	Swap	NYMEX	7/14 - 9/14	184,000	$96.00
Crude Oil	Swap	NYMEX	7/14 - 9/14	92,000	$96.25
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$94.25
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$95.00
Crude Oil	Swap	NYMEX	7/14 - 12/14	184,000	$95.25
Natural Gas	Swap	NYMEX	1/14 - 12/14	7,300,000	$4.13
Natural Gas	Swap	NYMEX	1/14 - 12/14	3,650,000	$4.05
Natural Gas	Swap	NYMEX	1/14 - 12/14	3,650,000	$4.10
Natural Gas	Swap	NYMEX	1/15 - 12/15	3,650,000	$4.28

Construction materials and contracting

- Approximate work backlog as of December 31, 2013, was $456 million, compared to $406 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, reclamation and harbor expansions.

- The Company's approximate backlog in North Dakota as of December 31, 2013, was $97 million. North Dakota backlog was $46 million a year ago.

- Projected revenues included in the Company's 2014 earnings guidance are in the range of $1.6 billion to $1.8 billion.

- The Company anticipates margins in 2014 to be in line with 2013 margins.

- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, wind towers and geothermal. Initiatives are aimed at capturing additional market share and expanding into new markets.

- As the country's sixth-largest sand and gravel producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

Construction services

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Approximate work backlog as of December 31, 2013, was $459 million, compared to $325 million a year ago. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including refinery work.

- Projected revenues included in the Company's 2014 earnings guidance are in the range of $1.0 billion to $1.1 billion.

- The Company anticipates lower margins in 2014 compared to 2013.

- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, substations, utility services, as well as solar. Initiatives are aimed at capturing additional market share and expanding into new markets.

New Accounting Standards
For information regarding new accounting standards, see 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. There is risk that lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in additional future noncash write-downs of the Company's oil and natural gas properties.

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, 2013, 2012, and 2011, there were no impairment losses recorded. At December 31, 2013, 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 10 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 2013. 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 2013.

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 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, 2013.

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 additional 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 $5.0 million for the year ended December 31, 2013.

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, 2013, the Company had cash and cash equivalents of $45.2 million and available capacity of $569.4 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 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.

Cash flows provided by operating activities in 2012 decreased $41.9 million from 2011, largely due to higher working capital requirements of $82.6 million, primarily at the exploration and production business and the electric and natural gas distribution businesses. Excluding working capital requirements, the Company experienced increased cash flows from operating activities primarily at the construction services business. In addition, excluding the effect of the write-downs of oil and natural gas properties, the decrease was partially offset by higher deferred income taxes of $18.5 million, largely due to increased capital expenditures at the exploration and production business.

Investing activities 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.

Cash flows used in investing activities in 2012 increased $423.4 million from 2011 primarily due to higher ongoing capital expenditures of $375.9 million, largely at the exploration and production and electric and natural gas distribution businesses, as well as increased acquisition-related capital expenditures at the pipeline and energy services business. Lower investments partially offset the increase in cash flows used in investing activities.

Financing activities 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.

Cash flows provided by financing activities in 2012 increased $410.8 million from 2011, primarily due to higher issuance of long-term debt and short-term borrowings of $467.7 million and $20.1 million, respectively, as well as lower repayment of short-term borrowings of $20.0 million. Partially offsetting the increase in cash flows provided by financing activities was higher repayment of long-term debt of $53.6 million, as well as higher dividends paid of $36.4 million resulting from the Company accelerating the payment date for the quarterly common stock dividend to December 31, 2012 from January 1, 2013.

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, 2013, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $67.9 million. Pretax pension expense reflected in the years ended December 31, 2013, 2012 and 2011, was $3.0 million, $204,000 and $3.7 million, respectively. The Company's pension expense is currently projected to be approximately $2.5 million to $3.5 million in 2014. Funding for the pension plans is actuarially determined. The minimum required contributions for 2013, 2012 and 2011 were approximately $13.2 million, $16.1 million and $9.3 million, respectively. For more information on the Company's pension plans, see Item 8 - Note 16.

Capital expenditures

The Company's capital expenditures for 2011 through 2013 and as anticipated for 2014 through 2016 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2011	2012	2013	2014	2015	2016
	(In millions)					
Capital expenditures:						
Electric	$52	$112	$169	$161	$140	$88
Natural gas distribution	71	130	101	141	166	139
Pipeline and energy services**	45	134	127	162	44	67
Exploration and production	273	554	391	441	501	518
Construction materials and contracting	52	45	35	38	69	58
Construction services	10	15	15	22	14	15
Other	19	1	2	1	3	3
Net proceeds from sale or disposition of property and other	(41)	(57)	(112)	(7)	(5)	(7)
Net capital expenditures	481	934	728	959	932	881
Retirement of long-term debt	85	139	424	12	269	294
	$566	$1,073	$1,152	$971	$1,201	$1,175

* 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.
** 2012 includes a 50 percent undivided interest in the Pronghorn oil and natural gas gathering and processing assets, as discussed in Item 8 - Note 2. 2013 - 2016 include the Company's share of capital expenditures related to Dakota Prairie Refinery and excludes expenditures related to the proposed 375-mile natural gas pipeline at the pipeline and energy services business, as discussed in Prospective Information and Item 8 - Note 19.

Capital expenditures for 2013, 2012 and 2011 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 $(56.8) million in 2013, $33.7 million in 2012 and $24.0 million in 2011.

The 2013 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 2014 through 2016 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, acquisition of additional leasehold acreage and exploratory drilling at the exploration and production segment
- Power generation and transmission opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- The Company's proportionate share of Dakota Prairie Refinery at the pipeline and energy services segment
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the 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 2014 through 2016 will be met 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.

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, 2013. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For additional information on the covenants, certain other conditions and cross-default provisions, see Item 8 - Note 9.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2013:

Company	Facility		Facility Limit (In millions)		Amount Outstanding		Letters of Credit		Expiration Date
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$125.0		$78.9	(b)	$—		10/4/17
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)	$3.0		$—		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$500.0		$75.0	(b)	$—		6/8/17

(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 $150 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letter of credit, as discussed in Item 8 - Note 19, reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90 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 $650 million). There were no amounts outstanding under the credit agreement.

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

The following includes information related to the preceding table.

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

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

The Company's coverage of fixed charges including preferred stock dividends was 4.8 times for the 12 months ended December 31, 2013. Due to the $246.8 million after-tax noncash write-downs of oil and natural gas properties in 2012, earnings were insufficient by $51.2 million to cover fixed charges for the 12 months ended December 31, 2012. If the $246.8 million after-tax noncash write-downs were excluded, the coverage of fixed charges including preferred stock dividends would have been 4.4 times for the 12 months ended December 31, 2012.

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

Total equity as a percent of total capitalization was 60 percent at both December 31, 2013 and 2012. 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 are expected to be used for corporate development purposes and other general corporate purposes. The Company issued 499,330 shares of stock during the fourth quarter of 2013 under the Equity Distribution Agreement, receiving net proceeds of $14.6 million.

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

Cascade Natural Gas Corporation On July 9, 2013, Cascade entered into a revolving credit agreement which replaced the previous revolving credit agreement and extended the termination date to July 9, 2018.

Intermountain Gas Company On July 15, 2013, Intermountain entered into a revolving credit agreement which replaced the previous revolving credit agreement and extended the termination date to July 13, 2018.

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

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

WBI Energy Transmission, Inc. On September 12, 2013, WBI Energy Transmission entered into a $175 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2013, which reduced capacity under this uncommitted private shelf agreement.

Off balance sheet arrangements

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

Centennial continues to guarantee CEM's obligations under a construction contract for an electric generating facility near Hobbs, New Mexico. For more information, see Item 8 - Note 19.

Contractual obligations and commercial commitments

For more information on the Company's contractual obligations on derivative instruments, long-term debt, operating leases and purchase commitments, see Item 8 - Notes 7, 9 and 19. At December 31, 2013, the Company's commitments under these obligations were as follows:

	2014	2015	2016	2017	2018	Thereafter	Total
	(In millions)						
Long-term debt	$12.3	$269.4	$293.8	$204.9	$130.2	$944.0	$1,854.6
Estimated interest payments*	92.2	88.2	66.2	56.7	53.8	466.1	823.2
Operating leases	32.8	26.6	22.2	17.8	13.5	45.7	158.6
Purchase commitments	635.8	281.6	170.7	100.3	73.4	910.8	2,172.6
Commodity derivatives	7.5	—	—	—	—	—	7.5
	$780.6	$665.8	$552.9	$379.7	$270.9	$2,366.6	$5,016.5

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

At December 31, 2013, the Company had total liabilities of $98.5 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was approximately $18.0 million at December 31, 2013, 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 $14.9 million 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 2014, which are not reflected in the previous table, are $10.9 million. For information on potential contributions above the minimum funding requirements, see Item 8 - Note 16.

The Company's multiemployer plan 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 multiemployer plans 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 2013, 2012 or 2011.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

For more information on 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, 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

The following table summarizes derivative agreements entered into by Fidelity as of December 31, 2012. These agreements call for Fidelity to receive fixed prices and pay variable prices.

(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Oil swap agreements maturing in 2013	$99.83	1,825	$12,038
Natural gas swap agreements maturing in 2013	$3.89	10,950	$3,753

	Weighted Average Floor/Ceiling Price (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value

Oil collar agreements maturing in 2013	$92.50/$107.03	730	$2,513

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.

Centennial entered into interest rate swap agreements to manage a portion of its interest rate exposure on the forecasted issuance on long-term debt. The agreements called for Centennial to receive payments from or make payments to counterparties based on the difference between fixed and variable rates as specified by the interest rate swap agreements.

At December 31, 2013, the Company had no outstanding interest rate hedges.

The following table summarizes derivative instruments entered into by Centennial as of December 31, 2012. The agreements call for Centennial to receive variable rates and pay fixed rates.

(Notional amount and fair value in thousands)

	Weighted Average Fixed Interest Rate	Notional Amount	Fair Value
Interest rate swap agreements with mandatory termination dates in 2013	3.22%	$50,000	$(6,255)

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, 2013.

	2014	2015	2016	2017	2018	Thereafter	Total	Fair Value
	(Dollars in millions)							
Long-term debt:								
Fixed rate	$9.3	$266.4	$288.5	$43.5	$108.4	$906.5	$1,622.6	$1,683.0
Weighted average interest rate	6.9%	5.7%	6.4%	6.3%	6.1%	5.1%	5.6%	—
Variable rate	$3.0	$3.0	$5.3	$161.4	$21.8	$37.5	$232.0	$229.6
Weighted average interest rate	1.2%	1.2%	1.8%	.5%	2.0%	2.4%	1.0%	—

Foreign currency risk
The Company's investment in ECTE is exposed to market risks from changes in foreign currency exchange rates between the U.S. dollar and the Brazilian Real. For more information, see Item 8 - Note 4. At December 31, 2013 and 2012, the Company had no outstanding foreign currency hedges.

58

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, 2013. 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 (1992).

Based on our evaluation under the framework in Internal Control-Integrated Framework (1992), management concluded that the Company's internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2013, 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, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the 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, 2013, based on the criteria established in Internal Control-Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 21, 2014

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, 2013, based on criteria established in Internal Control-Integrated Framework (1992) 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, 2013, based on the criteria established in Internal Control-Integrated Framework (1992) 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, 2013 of the Company and our report dated February 21, 2014 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 21, 2014

MDU RESOURCES GROUP, INC.
Consolidated Statements of Income

Years ended December 31,	2013	2012	2011
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	$1,264,574	$1,131,626	$1,343,714
Exploration and production, construction materials and contracting, construction services and other	3,197,830	2,943,805	2,706,778
Total operating revenues	4,462,404	4,075,431	4,050,492
Operating expenses:			
Fuel and purchased power	83,528	72,380	64,485
Purchased natural gas sold	505,065	425,220	572,187
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	269,825	254,194	275,866
Exploration and production, construction materials and contracting, construction services and other	2,535,872	2,377,285	2,215,269
Depreciation, depletion and amortization	386,856	359,205	343,395
Taxes, other than income	188,359	176,140	172,923
Write-downs of oil and natural gas properties (Note 1)	—	391,800	—
Total operating expenses	3,969,505	4,056,224	3,644,125
Operating income	492,899	19,207	406,367
Earnings (loss) from equity method investments	(132)	5,383	4,693
Other income	6,768	6,642	6,520
Interest expense	83,917	76,699	81,354
Income (loss) before income taxes	415,618	(45,467)	336,226
Income taxes	136,736	(31,146)	110,274
Income (loss) from continuing operations	278,882	(14,321)	225,952
Income (loss) from discontinued operations, net of tax (Note 3)	(312)	13,567	(12,926)
Net income (loss)	278,570	(754)	213,026
Net loss attributable to noncontrolling interest	(363)	—	—
Dividends declared on preferred stocks	685	685	685
Earnings (loss) on common stock	$278,248	$(1,439)	$212,341
Earnings (loss) per common share - basic:			
Earnings (loss) before discontinued operations	$1.47	$(.08)	$1.19
Discontinued operations, net of tax	—	.07	(.07)
Earnings (loss) per common share - basic	$1.47	$(.01)	$1.12
Earnings (loss) per common share - diluted:			
Earnings (loss) before discontinued operations	$1.47	$(.08)	$1.19
Discontinued operations, net of tax	—	.07	(.07)
Earnings (loss) per common share - diluted	$1.47	$(.01)	$1.12
Weighted average common shares outstanding - basic	188,855	188,826	188,763
Weighted average common shares outstanding - diluted	189,693	188,826	188,905

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

MDU RESOURCES GROUP, INC.
Consolidated Statements of Comprehensive Income

Years ended December 31,	2013	2012	2011
	(In thousands)		
Net income (loss)	$278,570	$(754)	$213,026
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 $(3,116), $4,829 and $4,683 in 2013, 2012 and 2011, respectively	(5,594)	8,497	7,900
Reclassification adjustment for (gain) loss on derivative instruments included in net income, net of tax of $(2,548), $(5,141) and $0 in 2013, 2012 and 2011, respectively	(4,189)	(8,754)	