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.

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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

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

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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.

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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.

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

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	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.

	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

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.

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)	—
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(9,783)	(257)	7,900
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $11,818, $(2,060) and $(14,205) in 2013, 2012 and 2011, respectively	18,539	(3,106)	(23,473)
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $1,276, $1,379 and $632 in 2013, 2012 and 2011, respectively	2,001	2,079	1,046
Postretirement liability adjustment	20,540	(1,027)	(22,427)
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $(177), $(296) and $(767) in 2013, 2012 and 2011, respectively	(299)	(476)	(1,189)
Reclassification adjustment for (gain) loss on foreign currency translation adjustment included in net income, net of tax of $70, $2 and $(65) in 2013, 2012 and 2011, respectively	143	3	(106)
Foreign currency translation adjustment	(156)	(473)	(1,295)
Net unrealized gain (loss) on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(105), $(52) and $(20) in 2013, 2012 and 2011, respectively	(194)	(97)	(36)
Reclassification adjustment for loss on available-for-sale investments included in net income, net of tax of $59, $72 and $64 in 2013, 2012 and 2011, respectively	109	134	118
Net unrealized gain (loss) on available-for-sale investments	(85)	37	82
Other comprehensive income (loss)	10,516	(1,720)	(15,740)
Comprehensive income (loss)	289,086	(2,474)	197,286
Comprehensive loss attributable to noncontrolling interest	(363)	—	—
Comprehensive income (loss) attributable to common stockholders	$289,449	$(2,474)	$197,286

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

MDU RESOURCES GROUP, INC.
Consolidated Balance Sheets

December 31,	2013	2012
(In thousands, except shares and per share amounts)		
Assets		
Current assets:		
Cash and cash equivalents	$45,225	$49,042
Receivables, net	713,067	678,123
Inventories	282,391	317,415
Deferred income taxes	25,048	22,846
Commodity derivative instruments	1,447	18,304
Prepayments and other current assets	49,510	42,351
Total current assets	1,116,688	1,128,081
Investments	112,939	103,243
Property, plant and equipment (Note 1)	8,803,866	8,107,751
Less accumulated depreciation, depletion and amortization	3,872,487	3,608,912
Net property, plant and equipment	4,931,379	4,498,839
Deferred charges and other assets:		
Goodwill (Note 5)	636,039	636,039
Other intangible assets, net (Note 5)	13,099	17,129
Other	251,188	299,160
Total deferred charges and other assets	900,326	952,328
Total assets	$7,061,332	$6,682,491
Liabilities and Equity		
Current liabilities:		
Short-term borrowings (Note 9)	$11,500	$28,200
Long-term debt due within one year	12,277	134,108
Accounts payable	404,961	388,015
Taxes payable	74,175	46,475
Dividends payable	33,737	171
Accrued compensation	69,661	48,448
Commodity derivative instruments	7,483	—
Other accrued liabilities	171,106	204,698
Total current liabilities	784,900	850,115
Long-term debt (Note 9)	1,842,286	1,610,867
Deferred credits and other liabilities:		
Deferred income taxes	859,306	755,102
Other liabilities	718,938	818,159
Total deferred credits and other liabilities	1,578,244	1,573,261
Commitments and contingencies (Notes 16, 18 and 19)		
Equity:		
Preferred stocks (Note 11)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 12)		
Authorized - 500,000,000 shares, $1.00 par value	189,869	189,369
Issued - 189,868,780 shares in 2013 and 189,369,450 shares in 2012		
Other paid-in capital	1,056,996	1,039,080
Retained earnings	1,603,130	1,457,146

Accumulated other comprehensive loss	(38,205)	(48,721)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,808,164	2,633,248
Total stockholders' equity	2,823,164	2,648,248
Noncontrolling interest	32,738	—
Total equity	2,855,902	2,648,248
Total liabilities and equity	$7,061,332	$6,682,491

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

MDU RESOURCES GROUP, INC.
Consolidated Statements of Equity
Years ended December 31, 2013, 2012 and 2011

	Preferred Stock		Common Stock		Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock		Non-controlling	Total
	Shares	Amount	Shares	Amount				Shares	Amount	Interest	
	(In thousands, except shares)										
Balance at December 31, 2010	150,000	$15,000	188,901,379	$188,901	$1,026,349	$1,497,439	$(31,261)	(538,921)	$(3,626)	$—	$2,69
Net income	—	—	—	—	—	213,026	—	—	—	—	213,02
Other comprehensive loss	—	—	—	—	—	—	(15,740)	—	—	—	(15,74
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685
Dividends declared on common stock	—	—	—	—	—	(123,657)	—	—	—	—	(123,6
Stock-based compensation	—	—	423,591	424	10,164	—	—	—	—	—	10,58
Net tax deficit on stock-based compensation	—	—	—	—	(909)	—	—	—	—	—	(909
Issuance of common stock	—	—	7,515	7	135	—	—	—	—	—	142
Balance at December 31, 2011	150,000	15,000	189,332,485	189,332	1,035,739	1,586,123	(47,001)	(538,921)	(3,626)	—	2,775,
Net loss	—	—	—	—	—	(754)	—	—	—	—	(754
Other comprehensive loss	—	—	—	—	—	—	(1,720)	—	—	—	(1,720
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685
Dividends declared on common stock	—	—	—	—	—	(127,538)	—	—	—	—	(127,5
Stock-based compensation	—	—	25,743	26	5,094	—	—	—	—	—	5,120
Net tax deficit on stock-based compensation	—	—	—	—	(1,958)	—	—	—	—	—	(1,958
Issuance of common stock	—	—	11,222	11	205	—	—	—	—	—	216
Balance at December 31,	150,000	15,000	189,369,450	189,369	1,039,080	1,457,146	(48,721)	(538,921)	(3,626)	—	2,648,

2012											
Net income (loss)	—	—	—	—	—	278,933	—	—	—	(363)	278,57
Other comprehensive income	—	—	—	—	—	—	10,516	—	—	—	10,516
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685
Dividends declared on common stock	—	—	—	—	—	(132,264)	—	—	—	—	(132,2
Stock-based compensation	—	—	—	—	5,281	—	—	—	—	—	5,281
Net tax deficit on stock-based compensation	—	—	—	—	(1,419)	—	—	—	—	—	(1,419
Issuance of common stock	—	—	499,330	500	14,054	—	—	—	—	—	14,554
Contribution from non-controlling interest	—	—	—	—	—	—	—	—	—	33,101	33,101
Balance at December 31, 2013	150,000	$15,000	189,868,780	$189,869	$1,056,996	$1,603,130	$(38,205)	(538,921)	$(3,626)	$32,738	$2,85

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

MDU RESOURCES GROUP, INC.
Consolidated Statements of Cash Flows

Years ended December 31,	2013	2012	2011
	(In thousands)		
Operating activities:			
Net income (loss)	$278,570	$(754)	$213,026
Income (loss) from discontinued operations, net of tax	(312)	13,567	(12,926)
Income (loss) from continuing operations	278,882	(14,321)	225,952
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	386,856	359,205	343,395
Earnings (loss), net of distributions, from equity method investments	2,281	(618)	(2,111)
Deferred income taxes	86,778	(7,503)	118,925
Unrealized (gain) loss on commodity derivatives	6,267	624	(1,827)
Write-downs of oil and natural gas properties (Note 1)	—	391,800	—
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(40,669)	(13,416)	(30,452)
Inventories	30,452	(42,334)	(24,226)
Other current assets	(9,474)	297	7,729
Accounts payable	15,084	6,352	(12,263)
Other current liabilities	29,392	(59,001)	33,738
Other noncurrent changes	(43,937)	(33,665)	(31,538)
Net cash provided by continuing operations	741,912	587,420	627,322
Net cash provided by (used in) discontinued operations	281	(2,680)	(674)
Net cash provided by operating activities	742,193	584,740	626,648
Investing activities:			
Capital expenditures	(909,400)	(872,920)	(497,000)
Acquisitions, net of cash acquired	—	(67,261)	(157)
Net proceeds from sale or disposition of property and other	124,541	40,110	40,107
Investments	302	9,725	(10,302)
Proceeds from sale of equity method investments	1,896	2,394	2,807
Net cash used in continuing operations	(782,661)	(887,952)	(464,545)
Net cash provided by discontinued operations	—	—	—
Net cash used in investing activities	(782,661)	(887,952)	(464,545)
Financing activities:			
Issuance of short-term borrowings	9,500	20,100	—
Repayment of short-term borrowings	—	—	(20,000)
Issuance of long-term debt	507,924	467,957	300
Repayment of long-term debt	(423,707)	(138,775)	(85,151)
Proceeds from issuance of common stock	14,554	88	5,744
Dividends paid	(98,405)	(159,768)	(123,323)
Excess tax benefit on stock-based compensation	—	26	1,239
Contribution from noncontrolling interest	27,000	—	—
Net cash provided by (used in) continuing operations	36,866	189,628	(221,191)
Net cash provided by discontinued operations	—	—	—
Net cash provided by (used in) financing activities	36,866	189,628	(221,191)
Effect of exchange rate changes on cash and cash equivalents	(215)	(146)	(214)
Decrease in cash and cash equivalents	(3,817)	(113,730)	(59,302)
Cash and cash equivalents - beginning of year	49,042	162,772	222,074
Cash and cash equivalents - end of year	$45,225	$49,042	$162,772

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

Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies
Basis of presentation
The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. Intercompany balances and transactions have been eliminated in consolidation, except for certain transactions related to the Company's regulated operations in accordance with GAAP. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

Management has also evaluated the impact of events occurring after December 31, 2013, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents
The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts
Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. For more information, see Percentage-of-completion method in this note. The total balance of receivables past due 90 days or more was $36.4 million and $34.3 million as of December 31, 2013 and 2012, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2013 and 2012, was $10.1 million and $10.8 million, respectively.

Inventories and natural gas in storage

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

	2013	2012
	(In thousands)	
Aggregates held for resale	$101,568	$87,715
Materials and supplies	69,808	69,390
Asphalt oil	38,099	67,480
Merchandise for resale	21,720	31,172
Natural gas in storage (current)	16,417	29,030
Other	34,779	32,628
Total	$282,391	$317,415

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $48.3 million and $49.7 million at December 31, 2013 and 2012, respectively.

Investments

The Company's investments include its equity method and cost method investments as discussed in Note 4, the cash surrender value of life insurance policies, an insurance contract, mortgage-backed securities and U.S. Treasury securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair value option for its mortgage-backed securities and U.S. Treasury securities and, as a result, the unrealized gains and losses on these investments are recorded in accumulated other comprehensive income (loss). For more information, see Notes 8 and 16.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and production properties as described in Oil and natural gas properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, at the exploration and production segment only on costs that have been excluded from the full cost amortization pool and on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized for the years ended December 31 were as follows:

	2013	2012	2011
	(In thousands)		
Interest capitalized	$6,033	$8,659	$10,821
AFUDC - borrowed	$2,767	$2,483	$1,666
AFUDC - equity	$3,322	$4,530	$2,587

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

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

	2013	2012	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$570,394	$546,011	42
Distribution	308,202	276,446	39
Transmission	196,824	180,543	48
Construction in progress	141,365	62,123	-
Other	99,037	85,461	14
Natural gas distribution:			
Distribution	1,384,587	1,308,314	40
Construction in progress	46,763	71,679	-
Other	345,551	309,957	25
Pipeline and energy services:			
Transmission	418,594	403,126	52
Gathering	39,597	42,420	19
Storage	42,939	42,058	51
Construction in progress	6,937	13,667	-
Other	39,504	38,386	29
Nonregulated:			
Pipeline and energy services:			
Midstream	213,063	233,840	17
Construction in progress	188,641	29,657	-
Other	12,897	13,379	11
Exploration and production:			
Oil and natural gas properties	3,017,879	2,723,356	*
Other	42,969	41,204	8
Construction materials and contracting:			
Land	125,551	126,788	-
Buildings and improvements	70,000	73,884	19
Machinery, vehicles and equipment	906,774	899,592	12
Construction in progress	13,315	11,165	-
Aggregate reserves	394,715	393,552	**
Construction services:			
Land	4,821	4,723	-
Buildings and improvements	16,628	16,563	20
Machinery, vehicles and equipment	105,991	100,445	6
Other	7,508	8,893	4
Other:			
Land	2,837	2,837	-
Other	47,160	47,682	23
Eliminations	(7,177)	—	
Less accumulated depreciation, depletion and amortization	3,872,487	3,608,912	
Net property, plant and equipment	$4,931,379	$4,498,839	

* Amortized on the units-of-production method based on total proved reserves at a BOE average rate of $17.41, $15.28 and $12.25 for the years ended December 31, 2013, 2012 and 2011, respectively. Includes oil and natural gas properties accounted for under the full-cost method, of which $124.9 million and $191.8 million were excluded from amortization at December 31, 2013 and 2012, respectively.

** Depleted on the units-of-production method.

Impairment of long-lived assets
The Company reviews the carrying values of its long-lived assets, excluding goodwill and oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In 2013 and 2012, the Company recognized impairments of $9.0 million (after tax) and $1.7 million (after tax), respectively, which are recorded in operation and maintenance expense on the Consolidated Statements of Income. The impairments are related to coalbed natural gas gathering assets located in Wyoming and Montana where there has been a significant decline in natural gas development and production activity largely due to low natural gas prices. The coalbed natural gas gathering assets were written down to fair value that was determined using the income approach. For more information on this nonrecurring fair value measurement, see Note 8.

No significant impairment losses were recorded in 2011. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

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

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Note 15. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 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.

Oil and natural gas properties

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

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

At December 31, 2013, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, 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.

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

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

The following table summarizes the Company's oil and natural gas properties not subject to amortization at December 31, 2013, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2013	2012	2011	2010 and prior
	(In thousands)				
Acquisition	$93,758	$1,514	$23,588	$28,543	$40,113
Development	14,824	12,622	1,633	271	298
Exploration	14,547	9,952	4,346	198	51
Capitalized interest	1,740	340	418	410	572
Total costs not subject to amortization	$124,869	$24,428	$29,985	$29,422	$41,034

Costs not subject to amortization as of December 31, 2013, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Texas properties and the Paradox Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $107.4 million and $85.9 million at December 31, 2013 and 2012, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

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

Costs and estimated earnings in excess of billings on uncompleted contracts represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts represent billings in excess of revenues recognized and were included in accounts payable. Costs and estimated earnings in excess of billings and billings in excess of costs and estimated earnings on uncompleted contracts at December 31, were as follows:

	2013	2012
	(In thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	$60,828	$64,996
Billings in excess of costs and estimated earnings on uncompleted contracts	$84,189	$83,167

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

	2013	2012
	(In thousands)	
Short-term retainage *	$55,906	$54,256
Long-term retainage **	4,229	2,038
Total retainage	$60,135	$56,294

* Expected to be paid within one year or less and included in receivables, net.
** Included in deferred charges and other assets - other.

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

The Company's policy generally allows the hedging of monthly forecasted sales of oil and natural gas production at Fidelity for a period up to 42 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical oil and natural gas production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value. The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

The Company's derivative instruments are reflected at fair value. For more information, see Note 8.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 10.

Legal costs
The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $16.9 million and $35.3 million at December 31, 2013 and 2012, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $12.1 million and $3.0 million at December 31, 2013 and 2012, respectively, which is included in prepayments and other current assets.

Insurance
Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $1 million per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $1 million per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made and reported basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

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

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

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

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

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

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options and performance share awards. In 2013 and 2011, there were no shares excluded from the calculation of diluted earnings per share. Diluted loss per common share for the year ended December 31, 2012, was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the year. Due to the loss on common stock for the year ended December 31, 2012, the effect of outstanding performance share awards was excluded from the computation of diluted loss per common share as their effect was antidilutive.

Common stock outstanding includes issued shares less shares held in treasury. Net income (loss) was the same for both the basic and diluted earnings (loss) per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings (loss) per share calculation was as follows:

	2013	2012	2011
	(In thousands)		
Weighted average common shares outstanding - basic	188,855	188,826	188,763
Effect of dilutive stock options and performance share awards	838	—	142
Weighted average common shares outstanding - diluted	189,693	188,826	188,905
Shares excluded from the calculation of diluted earnings per share	—	58	—

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

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

	2013	2012	2011
	(In thousands)		
Interest, net of amount capitalized	$81,689	$74,378	$78,133
Income taxes paid (refunded), net	$24,857	$3,277	$(12,287)

Noncash investing transactions at December 31 were as follows:

	2013	2012	2011
	(In thousands)		
Property, plant and equipment additions in accounts payable	$67,129	$76,205	$41,540

New accounting standards
Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income In February 2013, the FASB issued guidance on the reporting of amounts reclassified out of accumulated other comprehensive income. This guidance requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required to be reclassified in its entirety to net income. Entities may present this information either on the face of the statement where net income is presented or in the notes. This guidance was effective for the Company on January 1, 2013, and is to be applied prospectively. The guidance required additional disclosures, however it did not impact the Company's results of operations, financial position or cash flows.

Disclosures about Offsetting Assets and Liabilities In December 2011, the FASB issued guidance on the disclosure requirements related to balance sheet offsetting. The new disclosure requirements relate to the nature of an entity's rights of offset and related arrangements associated with its financial instruments and derivative instruments. In January 2013, the FASB issued guidance clarifying the scope of the disclosures related to balance sheet offsetting. The amendments clarify that this guidance only applies to derivative instruments, repurchase agreements and securities lending transactions that are either offset or subject to an enforceable master netting arrangement. The guidance was effective for the Company on January 1, 2013, and must be applied retrospectively. The guidance required additional disclosures, however it did not impact the Company's results of operations, financial position or cash flows.

Variable interest entities

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

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

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

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gains (losses) on available-for-sale investments. For more information on derivative instruments, see Note 7.

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2013, 2012 and 2011, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at December 31, 2011	$6,275	$(53,320)	$(38)	$ 82	$(47,001)
Current-period other comprehensive income (loss)	(257)	(1,027)	(473)	37	(1,720)
Balance at December 31, 2012	6,018	(54,347)	(511)	119	(48,721)
Other comprehensive income (loss) before reclassifications	(5,594)	18,539	(299)	(194)	12,452
Amounts reclassified from accumulated other comprehensive loss	(4,189)	2,001	143	109	(1,936)
Net current-period other comprehensive income (loss)	(9,783)	20,540	(156)	(85)	10,516
Balance at December 31, 2013	$(3,765)	$(33,807)	$(667)	$ 34	$(38,205)

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

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

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

Note 2 - Acquisitions

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

In 2011, contingent consideration, consisting of the Company's common stock and cash, of $298,000 was made with respect to an acquisition made prior to 2011.

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

Note 3 - Discontinued Operations

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources had agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. The Company incurs legal expenses and has accrued liabilities related to this matter. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In 2011, the Company also incurred legal expenses related to this matter and in the first quarter had an income tax benefit related to favorable resolution of certain tax matters. In the second quarter of 2012, discontinued operations reflected the settlement of certain liabilities and estimated insurance recoveries resulting in a net benefit related to this matter. In the fourth quarter of 2012, the Company reversed its previously recorded accrual for the arbitration charge due to a favorable court ruling, which was partially offset by the reversal of estimated insurance recoveries. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For more information, see Note 19.

Note 4 - Equity Method Investments
Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. At December 31, 2013, the Company had no significant equity method investments.

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

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale of its entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE. The Company's remaining interest in ECTE is being sold over a four-year period. In August 2013 and 2012, and November 2011, the Company completed the sale of one-fourth of the remaining interest in each year. The Company recognized immaterial gains in 2013 and 2012 and a $1.0 million ($600,000 after tax) gain in 2011. The Company's remaining ownership interest in ECTE is being accounted for under the cost method.

At December 31, 2012, the equity method investments had total assets of $129.0 million and long-term debt of $65.5 million. The Company's investment in its equity method investments was approximately $6.9 million, including undistributed earnings of $3.4 million, at December 31, 2012.

Note 5 - Goodwill and Other Intangible Assets
The changes in the carrying amount of goodwill for the year ended December 31, 2013, were as follows:

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

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

The changes in the carrying amount of goodwill for the year ended December 31, 2012, were as follows:

	Balance at January 1, 2012 *	Goodwill Acquired During the Year **	Balance at December 31, 2012 *
	(In thousands)		
Natural gas distribution	$345,736	$—	$345,736
Pipeline and energy services	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	103,168	1,108	104,276
Total	$634,931	$1,108	$636,039

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.
** Includes contingent consideration that was not material related to an acquisition in a prior period.

Other amortizable intangible assets at December 31 were as follows:

	2013	2012
	(In thousands)	
Customer relationships	$21,310	$21,310
Accumulated amortization	(13,726)	(11,701)
	7,584	9,609
Noncompete agreements	6,186	7,236
Accumulated amortization	(4,840)	(5,326)
	1,346	1,910
Other	10,995	10,979
Accumulated amortization	(6,826)	(5,369)
	4,169	5,610
Total	$13,099	$17,129

Amortization expense for amortizable intangible assets for the years ended December 31, 2013, 2012 and 2011, was $4.0 million, $3.8 million and $3.7 million, respectively. Estimated amortization expense for intangible assets is $3.2 million in 2014, $2.5 million in 2015, $2.2 million in 2016, $2.0 million in 2017, $1.0 million in 2018 and $2.2 million thereafter.

Note 6 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period *	2013	2012
		(In thousands)	
Regulatory assets:			
Deferred income taxes	**	$125,607	$121,781
Pension and postretirement benefits (a)	(e)	105,123	166,477
Taxes recoverable from customers (a)	Over plant lives	18,266	9,078
Manufactured gas plant sites remediation (a)	Up to 4 years	15,797	15,828
Natural gas costs recoverable through rate adjustments (b)	Up to 28 months	12,060	2,981
Long-term debt refinancing costs (a)	Up to 25 years	8,697	9,144
Costs related to identifying generation development (a)	Up to 13 years	4,512	5,773
Other (a) (b)	Largely within 1- 5 years	15,311	20,132
Total regulatory assets		305,373	351,194
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		308,431	296,037
Deferred income taxes**		64,914	82,077
Taxes refundable to customers (c)		20,180	24,212
Natural gas costs refundable through rate adjustments (d)		16,932	35,328
Other (c) (d)		21,868	12,828
Total regulatory liabilities		432,325	450,482
Net regulatory position		$(126,952)	$(99,288)

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

** Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.

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

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

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

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

(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of December 31, 2013 and 2012, approximately $163.7 million and $215.6 million, respectively, of regulatory assets were not earning a rate of return.

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

Note 7 - Derivative Instruments

Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. The Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2013, the Company had no outstanding foreign currency hedges.

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

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2013 and 2012, credit risk was not material.

Fidelity
At December 31, 2013 and 2012, Fidelity held oil swap and collar agreements with total forward notional volumes of 2.9 million and 2.6 million Bbl, respectively, and natural gas swap agreements with total forward notional volumes of 18.3 million and 11.0 million MMBtu, respectively. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas on its forecasted sales of oil and natural gas production.

Effective April 1, 2013, Fidelity elected to de-designate all commodity derivative contracts previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively for all of its commodity derivative instruments. When the criteria for hedge accounting is not met or when hedge accounting is not elected, realized gains and losses and unrealized gains and losses are both recorded in operating revenues on the Consolidated Statements of Income. As a result of discontinuing hedge accounting on commodity derivative instruments, gains and losses on the oil and natural gas derivative instruments remain in accumulated other comprehensive income (loss) as of the de-designation date and are reclassified into earnings in future periods as the underlying hedged transactions affect earnings. At April 1, 2013, accumulated other comprehensive income (loss) included $1.8 million of unrealized gains, representing the mark-to-market value of the Company's commodity derivative instruments that qualified as cash flow hedges as of the balance sheet date. The Company expects to reclassify into earnings from accumulated other comprehensive income (loss) the remaining value related to de-designating commodity derivative instruments over the next 12 months.

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

Centennial
At December 31, 2013, Centennial had no outstanding interest rate swap agreements. At December 31, 2012, Centennial held interest rate swap agreements with a total notional amount of $50.0 million, which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt.

Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings.

Fidelity and Centennial

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

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

	2013	2012	2011
	(In thousands)		
Commodity derivatives designated as cash flow hedges:			
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	$(6,153)	$10,209	$10,806
Amount of gain reclassified from accumulated other comprehensive loss into operating revenues (effective portion), net of tax	(4,916)	(8,788)	—
Amount of gain (loss) recognized in operating revenues (ineffective portion), before tax	(1,422)	(730)	1,827
Interest rate derivatives designated as cash flow hedges:			
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	559	(1,712)	(2,906)
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	727	34	—
Amount of loss recognized in interest expense (ineffective portion), before tax	(769)	—	—
Commodity derivatives not designated as hedging instruments:			
Amount of gain (loss) recognized in operating revenues, before tax	(4,845)	106	—

Based on December 31, 2013, fair values, over the next 12 months net losses of approximately $700,000 (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2013 and 2012, were $7.5 million and $6.3 million, respectively. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2013 and 2012, were $7.5 million and $6.3 million, respectively.

The location and fair value of the Company's derivative instruments on the Consolidated Balance Sheets were as follows:

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2013	Fair Value at December 31, 2012
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$—	$18,084
		—	18,084
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	1,447	220
	Other assets - noncurrent	503	—
		1,950	220
Total asset derivatives		$1,950	$18,304

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Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2013 (In thousands)	Fair Value at December 31, 2012
Designated as hedges:			
Interest rate derivatives	Other accrued liabilities	$—	$6,255
		—	6,255
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	7,483	—
		7,483	—
Total liability derivatives		$7,483	$6,255

All of the Company's commodity and interest rate derivative instruments at December 31, 2013 and 2012, were subject to legally enforceable master netting agreements. However, the Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. The gross derivative assets and liabilities (excluding settlement receivables and payables that may be subject to the same master netting agreements) presented on the Consolidated Balance Sheets and the amount eligible for offset under the master netting agreements is presented in the following table:

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

December 31, 2012	Gross Amounts Recognized on the Consolidated Balance Sheets (In thousands)	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
Assets:			
Commodity derivatives	$18,304	$—	$18,304
Total assets	$18,304	$—	$18,304
Liabilities:			
Interest rate derivatives	$6,255	$—	$6,255
Total liabilities	$6,255	$—	$6,255

Note 8 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $62.4 million and $48.9 million as of December 31, 2013 and 2012, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the year ended December 31, 2013 and 2012, were $13.5 million and $5.2 million, respectively. The net unrealized loss on these investments for the year ended December 31, 2011, was $1.1 million. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

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

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

December 31, 2012	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$8,054	$144	$(3)	$8,195
U.S. Treasury securities	1,763	43	—	1,806
Total	$9,817	$187	$(3)	$10,001

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

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

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

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

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

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2013 and 2012, there were no transfers between Levels 1 and 2.

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

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

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

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
	(In thousands)			
Assets:				
Money market funds	$—	$24,240	$—	$24,240
Insurance contract*	—	48,898	—	48,898
Available-for-sale securities:				
Mortgage-backed securities	—	8,195	—	8,195
U.S. Treasury securities	—	1,806	—	1,806
Commodity derivative instruments	—	18,304	—	18,304
Total assets measured at fair value	$—	$101,443	$—	$101,443
Liabilities:				
Interest rate derivative instruments	$—	$6,255	$—	$6,255
Total liabilities measured at fair value	$—	$6,255	$—	$6,255

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

The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including long-lived asset impairments. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company reviews the carrying value of its long-lived assets, excluding goodwill and oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable. During the second quarters of 2013 and 2012, coalbed natural gas gathering assets were reviewed for impairment and found to be impaired and were written down to their estimated fair value using the income approach. Under this approach, fair value is determined by using the present value of future estimated cash flows. The factors used to determine the estimated future cash flows include, but are not limited to, internal estimates of gathering revenue, future commodity prices and operating costs and equipment salvage values. The estimated cash flows are discounted using a rate that approximates the weighted average cost of capital of a market participant. These fair value inputs are not typically observable. At June 30, 2012, certain coalbed natural gas gathering assets were written down to the nonrecurring fair value measurement of $2.5 million. At June 30, 2013, additional coalbed natural gas gathering assets were written down to the nonrecurring fair value measurement of $9.7 million. The fair value of these coalbed natural gas gathering assets have been categorized as Level 3 (Significant Unobservable Inputs) in the fair value hierarchy.

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

	2013 Carrying Amount	Fair Value	2012 Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$ 1,854,563	$ 1,912,590	$ 1,744,975	$ 1,888,135

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

Note 9 - Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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

Company	Facility		Facility Limit		Amount Outstanding at December 31, 2013		Amount Outstanding at December 31, 2012		Letters of Credit at December 31, 2013		Expiration Date
			(In millions)								
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$125.0		$ 78.9	(b)	$ 76.0	(b)	$ —		10/4/17
Cascade Natural Gas Corporation	Revolving credit agreement		$50.0	(c)	$ 11.5		$ 2.0		$ 2.2	(d)	7/9/18
Intermountain Gas Company	Revolving credit agreement		$65.0	(e)	$ 3.0		$ 26.2		$ —		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$500.0		$ 75.0	(b)	$ 217.0	(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 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

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agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings
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. Any borrowings under the revolving credit agreement would be classified as short-term borrowings as Cascade intends to repay the borrowings within one year. The weighted average interest rate for borrowings outstanding at December 31, 2013, was 3.3 percent.

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

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

Long-term debt
MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

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

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

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

On December 12, 2013, MDU Energy Capital entered into a note purchase agreement. MDU Energy Capital contracted to issue $30.0 million of Senior Notes under the agreement on January 27, 2014, with due dates ranging from January 2029 to January 2044 at a weighted average interest rate of 5.3 percent.

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. These borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings. The borrowings outstanding as of December 31, 2012, were classified as short-term borrowings because the previous revolving credit agreement expired within one year.

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

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

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

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

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

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. This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

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

	2013	2012
	(In thousands)	
Senior Notes at a weighted average rate of 5.52%, due on dates ranging from June 19, 2015 to April 15, 2044	$1,545,078	$1,349,160
Commercial paper at a weighted average rate of .40%, supported by revolving credit agreements	153,924	293,000
Term Loan Agreements at a weighted average rate of 2.08%, due on dates ranging from April 22, 2014 to April 22, 2023	75,000	—
Medium-Term Notes at a weighted average rate of 7.32%, due on dates ranging from September 15, 2027 to March 16, 2029	35,000	59,000
Other notes at a weighted average rate of 5.23%, due on dates ranging from September 1, 2020 to February 1, 2035	39,863	40,090
Credit agreements at a weighted average rate of 4.11%, due on dates ranging from February 28, 2014 to November 30, 2038	5,701	3,768
Discount	(3)	(43)

Total long-term debt	1,854,563	1,744,975
Less current maturities	12,277	134,108
Net long-term debt	$1,842,286	$1,610,867

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2013, aggregate $12.3 million in 2014; $269.4 million in 2015; $293.8 million in 2016; $204.9 million in 2017; $130.2 million in 2018 and $944.0 million thereafter.

Note 10 - Asset Retirement Obligations
The Company records obligations related to the plugging and abandonment of oil and natural gas wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations.

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

	2013	2012
	(In thousands)	
Balance at beginning of year	$102,545	$98,151
Liabilities incurred	5,610	6,523
Liabilities acquired	—	—
Liabilities settled	(22,257)	(10,472)
Accretion expense	4,574	4,266
Revisions in estimates	7,671	3,655
Other	386	422
Balance at end of year	$98,529	$102,545

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

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2013 and 2012, was $4.1 million and $5.0 million, respectively. The legally restricted assets consist primarily of money market funds and are reflected in other assets on the Consolidated Balance Sheets.

Note 11 - Preferred Stocks
Preferred stocks at December 31 were as follows:

	2013	2012
(In thousands, except shares and per share amounts)		
Authorized:		
Preferred -		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A -		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference -		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series - 100,000 shares	$10,000	$10,000
4.70% Series - 50,000 shares	5,000	5,000
Total preferred stocks	$15,000	$15,000

For the years 2013, 2012 and 2011, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

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

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

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

Note 12 - Common Stock

For the years 2013, 2012 and 2011, dividends declared on common stock were $.6950, $.6750 and $.6550 per common share, respectively.

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From January 2011 through December 2013, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2013, there were 15.6 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

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

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes, excluding noncash write-downs, for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.1 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2013. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $219 million of the Company's (excluding its subsidiaries) net assets, which represents common stockholders' equity including retained earnings, would be restricted from use for dividend payments at December 31, 2013. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2013, there are 6.2 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense (after tax) was $3.9 million, $4.0 million and $3.5 million in 2013, 2012 and 2011, respectively.

As of December 31, 2013, total remaining unrecognized compensation expense related to stock-based compensation was approximately $7.0 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock options

The Company had granted stock options to directors, key employees and employees. The Company has not granted stock options since 2003 and as of December 31, 2013 and 2012, there were no stock options outstanding.

The Company received cash of $88,000 and $5.7 million from the exercise of stock options for the years ended December 31, 2012 and 2011, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2012 and 2011, was $60,000 and $3.3 million, respectively.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 36,713 shares with a fair value of $1.1 million, 53,888 shares with a fair value of $1.1 million and 55,141 shares with a fair value of $1.1 million issued under this plan during the years ended December 31, 2013, 2012 and 2011, respectively.

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

Performance share awards

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

Target grants of performance shares outstanding at December 31, 2013, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2011	2011-2013	254,514
February 2012	2012-2014	251,196
March 2013	2013-2015	244,281

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2013, 2012 and 2011 were:

	2013	2012	2011
Grant-date fair value	$29.01	$17.18	$19.99
Blended volatility range	16.10 %- 19.39 %	24.29 %- 25.81 %	23.20 %- 32.18 %
Risk-free interest rate range	.09 %- .40 %	.10 %- .35 %	.09 %- 1.34 %
Discounted dividends per share	$2.12	$1.19	$1.23

There were no performance shares that vested in 2013, 2012 or 2011.

A summary of the status of the performance share awards for the year ended December 31, 2013, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	786,136	$18.17
Granted	264,614	29.01
Vested	—	—
Forfeited	(300,759)	18.20
Nonvested at end of period	749,991	$21.99

Note 14 - Income Taxes

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

2013	2012	2011

	(In thousands)		
United States	$415,202	$(47,175)	$333,486
Foreign	416	1,708	2,740
Income (loss) before income taxes from continuing operations	$415,618	$(45,467)	$336,226

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

	2013	2012	2011
	(In thousands)		
Current:			
Federal	$45,518	$(26,858)	$(7,188)
State	4,311	858	778
Foreign	(29)	(75)	127
	49,800	(26,075)	(6,283)
Deferred:			
Income taxes:			
Federal	78,953	(1,224)	105,528
State	8,031	(6,323)	13,157
Investment tax credit - net	(206)	44	240
	86,778	(7,503)	118,925
Change in uncertain tax positions	—	1,974	(1,048)
Change in accrued interest	158	458	(1,320)
Total income tax expense (benefit)	$136,736	$(31,146)	$110,274

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

	2013	2012
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$125,607	$121,781
Accrued pension costs	74,320	85,037
Alternative minimum tax credit carryforward	33,304	—
Compensation-related	31,550	23,441
Asset retirement obligations	29,578	26,748
Legal and environmental contingencies	10,710	8,046
Other	45,101	39,792
Total deferred tax assets	350,170	304,845
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	813,597	755,392
Basis differences on oil and natural gas producing properties	266,168	167,113
Regulatory matters	64,914	82,077
Intangible asset amortization	13,579	14,078
Other	26,170	18,441
Total deferred tax liabilities	1,184,428	1,037,101
Net deferred income tax liability	$(834,258)	$(732,256)

As of December 31, 2013 and 2012, no valuation allowance has been recorded associated with the previously identified deferred tax assets. The alternative minimum tax credit carryforwards do not expire.

The following table reconciles the change in the net deferred income tax liability from December 31, 2012, to December 31, 2013, to deferred income tax expense:

	2013
(In thousands)	
Change in net deferred income tax liability from the preceding table	$102,002

Deferred taxes associated with other comprehensive loss	(7,277)
Other	(7,947)
Deferred income tax expense for the period	$86,778

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

Years ended December 31,	2013		2012		2011	
	Amount	%	Amount	%	Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	$145,466	35.0	$(15,914)	35.0	$117,679	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	10,524	2.5	2,469	(5.4)	10,653	3.2
Nonqualified benefit plans	(5,173)	(1.2)	(2,359)	5.2	(2,918)	(.9)
Depletion allowance	(3,764)	(.9)	(3,728)	8.2	(3,266)	(1.0)
Federal renewable energy credit	(3,404)	(.8)	(3,401)	7.5	(3,485)	(1.0)
Deductible K-Plan dividends	(1,593)	(.4)	(2,829)	6.2	(2,282)	(.7)
AFUDC equity	(1,074)	(.3)	(1,500)	3.3	(873)	(.3)
Resolution of tax matters and uncertain tax positions	(859)	(.2)	2,559	(5.6)	(3,906)	(1.2)
Deferred tax rate changes	741	.2	(3,083)	6.8	(417)	(.1)
Other	(4,128)	(1.0)	(3,360)	7.3	(911)	(.2)
Total income tax expense (benefit)	$136,736	32.9	$(31,146)	68.5	$110,274	32.8

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

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $7.0 million at December 31, 2013. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2013, was approximately $2.2 million.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2007. The 2007 through 2009 tax years are currently under audit.

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

	2013	2012	2011
	(In thousands)		
Balance at beginning of year	$14,914	$11,206	$9,378
Additions for tax positions of prior years	—	3,708	4,172
Settlements	—	—	(2,344)
Balance at end of year	$14,914	$14,914	$11,206

Included in the balance of unrecognized tax benefits at December 31, 2013 and 2012, were $8.4 million and $8.4 million, respectively, of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $9.0 million, including approximately $2.5 million for the payment of interest and penalties at December 31, 2013, and was $8.5 million, including approximately

$2.0 million for the payment of interest and penalties at December 31, 2012.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2013, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2013, 2012 and 2011, the Company recognized approximately $1.2 million, $740,000 and $780,000, respectively, in interest expense. Penalties were not material in 2013, 2012 and 2011. The Company recognized interest income of approximately $660,000, $290,000 and $1.9 million for the years ended December 31, 2013, 2012 and 2011, respectively. The Company had accrued liabilities of approximately $2.8 million and $1.4 million at December 31, 2013 and 2012, respectively, for the payment of interest.

In September 2013, the Internal Revenue Service released final regulations relating to the capitalization of tangible personal property which are effective for tax years beginning on or after January 1, 2014. The Company does not expect these new regulations to have a material effect on its results of operations, financial position or cash flows.

Note 15 - Business Segment Data
The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these operating segments is defined based on the reporting and review process used by the Company's chief executive officer. The vast majority of the Company's operations are located within the United States. The Company also has an investment in a foreign country, which consists of Centennial Resources' investment in ECTE.

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

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

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

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

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

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

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

	2013	2012	2011
	(In thousands)		
External operating revenues:			
Electric	$257,260	$236,895	$225,468
Natural gas distribution	851,945	754,848	907,400
Pipeline and energy services	155,369	139,883	210,846
	1,264,574	1,131,626	1,343,714
Exploration and production	490,924	412,651	359,873
Construction materials and contracting	1,675,444	1,597,257	1,509,538
Construction services	1,029,909	932,013	834,918
Other	1,553	1,884	2,449
	3,197,830	2,943,805	2,706,778
Total external operating revenues	$4,462,404	$4,075,431	$4,050,492
Intersegment operating revenues:			
Electric	$—	$—	$—
Natural gas distribution	—	—	—
Pipeline and energy services	46,699	53,274	67,497
Exploration and production	45,099	35,966	93,713
Construction materials and contracting	36,693	20,168	472
Construction services	9,930	6,545	19,471
Other	8,067	8,486	8,997
Intersegment eliminations	(146,488)	(124,439)	(190,150)
Total intersegment operating revenues	$—	$—	$—
Depreciation, depletion and amortization:			
Electric	$32,789	$32,509	$32,177
Natural gas distribution	50,031	45,731	44,641
Pipeline and energy services	29,119	27,684	25,502
Exploration and production	186,458	160,681	142,645
Construction materials and contracting	74,470	79,527	85,459
Construction services	11,939	11,063	11,399
Other	2,050	2,010	1,572
Total depreciation, depletion and amortization	$386,856	$359,205	$343,395
Interest expense:			
Electric	$12,590	$12,421	$13,745
Natural gas distribution	25,123	28,726	29,444
Pipeline and energy services	10,330	7,742	10,516
Exploration and production	14,315	9,018	7,445
Construction materials and contracting	17,394	15,211	16,241
Construction services	4,306	4,435	4,473
Other	15	13	—
Intersegment eliminations	(156)	(867)	(510)
Total interest expense	$83,917	$76,699	$81,354

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	2013	2012	2011
	(In thousands)		
Income taxes:			
Electric	$9,683	$8,975	$7,242
Natural gas distribution	16,633	12,005	16,931
Pipeline and energy services	3,390	15,291	12,912
Exploration and production	53,197	(108,264)	46,298
Construction materials and contracting	24,765	14,099	11,227
Construction services	29,504	24,128	13,426
Other	2,433	2,620	2,238
Intersegment eliminations	(2,869)	—	—
Total income taxes	$136,736	$(31,146)	$110,274
Earnings (loss) on common stock:			
Electric	$34,837	$30,634	$29,258
Natural gas distribution	37,656	29,409	38,398
Pipeline and energy services	7,629	26,588	23,082
Exploration and production	94,450	(177,283)	80,282
Construction materials and contracting	50,946	32,420	26,430
Construction services	52,213	38,429	21,627
Other	5,136	4,797	6,190
Intersegment eliminations	(4,307)	—	—
Earnings (loss) on common stock before income (loss) from discontinued operations	278,560	(15,006)	225,267
Income (loss) from discontinued operations, net of tax*	(312)	13,567	(12,926)
Total earnings (loss) on common stock	$278,248	$(1,439)	$212,341
Capital expenditures:			
Electric	$168,557	$112,035	$52,072
Natural gas distribution	101,279	130,178	70,624
Pipeline and energy services	127,092	133,787	45,556
Exploration and production	391,315	554,528	272,855
Construction materials and contracting	34,607	45,083	52,303
Construction services	15,102	14,835	9,711
Other	2,249	791	18,759
Net proceeds from sale or disposition of property and other	(112,131)	(57,460)	(40,857)
Total net capital expenditures	$728,070	$933,777	$481,023
Assets:			
Electric**	$884,283	$760,324	$672,940
Natural gas distribution**	1,786,068	1,703,459	1,679,091
Pipeline and energy services	798,701	622,470	526,797
Exploration and production	1,616,131	1,539,017	1,481,556
Construction materials and contracting	1,305,808	1,371,252	1,374,026
Construction services	450,614	429,547	418,519
Other***	219,727	256,422	403,196
Total assets	$7,061,332	$6,682,491	$6,556,125

	2013	2012	2011
	(In thousands)		
Property, plant and equipment:			
Electric**	$1,315,822	$1,150,584	$1,068,524
Natural gas distribution**	1,776,901	1,689,950	1,568,866
Pipeline and energy services	962,172	816,533	719,291
Exploration and production	3,060,848	2,764,560	2,615,146
Construction materials and contracting	1,510,355	1,504,981	1,499,852
Construction services	134,948	130,624	124,796
Other	49,997	50,519	49,747
Eliminations	(7,177)	—	—
Less accumulated depreciation, depletion and amortization	3,872,487	3,608,912	3,361,208
Net property, plant and equipment	$4,931,379	$4,498,839	$4,285,014

* Reflected in the Other category.

** Includes allocations of common utility property.

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

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

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

Capital expenditures for 2013, 2012 and 2011 include noncash capital expenditure-related accounts payable and exclude capital expenditures of the noncontrolling interest related to Dakota Prairie Refinery. The net transactions were $(56.8) million in 2013, $33.7 million in 2012 and $24.0 million in 2011.

Note 16 - Employee Benefit Plans

Pension and other postretirement benefit plans

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

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

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

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

Changes in benefit obligation and plan assets for the years ended December 31, 2013 and 2012, and amounts recognized in the Consolidated Balance Sheets at December 31, 2013 and 2012, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$459,111	$435,618	$103,358	$110,689
Service cost	155	1,078	1,675	1,747
Interest cost	16,249	17,598	3,215	4,166
Plan participants' contributions	—	—	1,472	2,688
Amendments	—	—	—	(11,418)
Actuarial (gain) loss	(44,551)	30,939	(20,985)	3,469
Benefits paid	(28,192)	(26,122)	(7,009)	(7,983)
Benefit obligation at end of year	402,772	459,111	81,726	103,358
Change in net plan assets:				
Fair value of plan assets at beginning of year	309,184	278,000	74,361	68,085
Actual gain on plan assets	35,539	34,493	13,819	6,497
Employer contribution	18,313	22,813	1,900	5,074
Plan participants' contributions	—	—	1,472	2,688
Benefits paid	(28,192)	(26,122)	(7,009)	(7,983)
Fair value of net plan assets at end of year	334,844	309,184	84,543	74,361
Funded status - (under) over	$(67,928)	$(149,927)	$2,817	$(28,997)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	$—	$—	$9,679	$—
Other accrued liabilities (current)	—	—	(381)	(655)
Other liabilities (noncurrent)	(67,928)	(149,927)	(6,481)	(28,342)
Net amount recognized	$(67,928)	$(149,927)	$2,817	$(28,997)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	$135,061	$202,406	$11,314	$43,589
Prior service cost (credit)	365	437	(17,137)	(18,594)
Total	$135,426	$202,843	$(5,823)	$24,995

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities), see Note 6.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized on a straight-line basis over the expected average remaining service lives of active participants for non-frozen plans and over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation was amortized over a 20-year period ending 2012.

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

	2013	2012
	(In thousands)	
Projected benefit obligation	$402,772	$459,111
Accumulated benefit obligation	$402,772	$459,111
Fair value of plan assets	$334,844	$309,184

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

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
	(In thousands)					
Components of net periodic benefit cost:						
Service cost	$155	$1,078	$2,252	$1,675	$1,747	$1,443
Interest cost	16,249	17,598	19,500	3,215	4,166	4,700
Expected return on assets	(19,917)	(23,536)	(22,809)	(4,343)	(4,890)	(5,051)
Amortization of prior service cost (credit)	71	(46)	45	(1,457)	(1,438)	(2,677)
Recognized net actuarial loss	7,173	7,070	4,656	1,814	2,134	753
Curtailment loss (gain)	—	(1,023)	1,218	—	—	—
Amortization of net transition obligation	—	—	—	—	2,128	2,125
Net periodic benefit cost, including amount capitalized	3,731	1,141	4,862	904	3,847	1,293
Less amount capitalized	727	937	1,196	164	910	(50)
Net periodic benefit cost	3,004	204	3,666	740	2,937	1,343
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	(60,173)	19,982	76,310	(30,461)	1,863	23,863
Prior service credit	—	—	—	—	(11,418)	—
Amortization of actuarial loss	(7,173)	(7,070)	(4,656)	(1,814)	(2,134)	(753)
Amortization of prior service (cost) credit	(71)	1,069	(1,263)	1,457	1,438	2,677
Amortization of net transition obligation	—	—	—	—	(2,128)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	(67,417)	13,981	70,391	(30,818)	(12,379)	23,662
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	$(64,413)	$14,185	$74,057	$(30,078)	$(9,442)	$25,005

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2014 are $4.8 million and $71,000, respectively. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2014 are $793,000 and $1.4 million, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

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

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012

Discount rate	4.53	%	3.65	%	4.48	%	3.67	%
Expected return on plan assets	7.00	%	7.00	%	6.00	%	6.00	%
Rate of compensation increase	N/A		N/A		3.00	%	4.00	%

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

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Discount rate	3.65 %	4.16 %	3.67 %	4.13 %
Expected return on plan assets	7.00 %	7.75 %	6.00 %	6.75 %
Rate of compensation increase	N/A*	N/A*	4.00 %	4.00 %

* Effective September 30, 2012, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.

The expected rate of return on pension plan assets is based on the targeted asset allocation range of 60 percent to 70 percent equity securities and 30 percent to 40 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to 75 percent equity securities and 25 percent to 35 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

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

	2013	2012
Health care trend rate assumed for next year	6.0 %- 7.0 %	6.0 %- 8.0 %
Health care cost trend rate - ultimate	5.0 %- 6.0 %	5.0 %- 6.0 %
Year in which ultimate trend rate achieved	2017	2017

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

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2013:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 159	$ (135)
Effect on postretirement benefit obligation	$ 3,352	$ (2,920)

The Company's pension assets are managed by 16 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

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

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

The carrying value of the pension plans' Level 1 and Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high quality, short-term instruments of domestic and foreign issuers.

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

The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources.

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

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2013 and 2012, there were no transfers between Levels 1 and 2.

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

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

Total assets measured at fair value	$225,788	$106,506	$—	$332,294

* Collective and mutual funds invest approximately 11 percent in common stock of mid-cap U.S. companies, 34 percent in common stock of large-cap U.S. companies, 11 percent in U.S. Treasuries, 27 percent in corporate bonds and 17 percent in other investments.

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

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
	(In thousands)			
Assets:				
Cash equivalents	$2,145	$10,460	$—	$12,605
Equity securities:				
U.S. companies	86,981	—	—	86,981
International companies	39,818	—	—	39,818
Collective and mutual funds*	82,787	20,065	—	102,852
Corporate bonds	—	45,112	—	45,112
Municipal bonds	—	9,302	—	9,302
U.S. Treasury securities	7,980	4,534	—	12,514
Total assets measured at fair value	$219,711	$89,473	$—	$309,184

* Collective and mutual funds invest approximately 12 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 41 percent in corporate bonds and 8 percent in other investments.

The following table sets forth a summary of changes in the fair value of the pension plans' Level 3 assets for the year ended December 31, 2012:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Corporate Bonds
	(In thousands)
Balance at beginning of year	$289
Total realized/unrealized losses	(47)
Purchases, issuances and settlements (net)	(242)
Balance at end of year	$—

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

The estimated fair value of the other postretirement benefit plans' Level 1 and Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high-quality, short-term money market instruments that consist of municipal obligations.

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2013 and 2012, there were no transfers between Levels 1 and 2.

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

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

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

The fair value of the Company's other postretirement benefit plans' assets by asset class were as follows:

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
	(In thousands)			
Assets:				
Cash equivalents	$1,053	$1,991	$—	$3,044
Equity securities:				
U.S. companies	2,207	—	—	2,207
International companies	260	—	—	260
Insurance contract*	—	68,850	—	68,850
Total assets measured at fair value	$3,520	$70,841	$—	$74,361

* The insurance contract invests approximately 51 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 10 percent in mortgage-backed securities, 11 percent in corporate bonds and 13 percent in other investments.

The Company expects to contribute approximately $32.5 million to its defined benefit pension plans and approximately $1.5 million to its postretirement benefit plans in 2014.

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
	(In thousands)		
2014	$ 23,391	$ 5,596	$ 237
2015	23,645	5,584	230
2016	23,911	5,583	221
2017	24,439	5,543	211
2018	24,814	5,483	200
2019 - 2023	130,026	26,038	823

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company's net periodic benefit cost for these plans was $7.3 million, $8.1 million and $8.1 million in 2013, 2012 and 2011, respectively. The total projected benefit obligation for these plans was $106.9 million and $113.0 million at December 31, 2013 and 2012, respectively. The accumulated benefit obligation for these plans was $99.7 million and $107.5 million at December 31, 2013 and 2012, respectively. A weighted average discount rate of 4.32 percent and 3.44 percent at December 31, 2013 and 2012, respectively, and a rate of compensation increase of 4.00 percent and 3.00 percent at December 31, 2013 and 2012, were used to determine benefit obligations. A discount rate of 3.44 percent and 4.00 percent at December 31, 2013 and 2012, respectively, and a rate of compensation increase of 3.00 percent and 4.00 percent at December 31, 2013 and 2012, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $5.7 million in 2014; $6.7 million in 2015; $6.5 million in 2016; $6.7 million in 2017; $7.2 million in 2018 and $37.5 million for the years 2019 through 2023.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2013 and 2012 were $304,000 and $84,000, respectively.

The Company had investments of $98.1 million and $84.4 million at December 31, 2013 and 2012, respectively, consisting of equity securities of $53.5 million and $41.9 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $31.4 million and $32.7 million, respectively, and other investments of $13.2 million and $9.8 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $33.2 million in 2013, $29.3 million in 2012 and $27.1 million in 2011.

Multiemployer plans

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

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- Assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in some of its multiemployer plans, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2013 and 2012 is for the plan's year-end at December 31, 2012, and December 31, 2011, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2013	Pension Protection Act Zone Status 2012	FIP/RP Status Pending/Implemented	Contributions 2013	Contributions 2012	Contributions 2011	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green as of 12/31/2013	Green as of 12/31/2012	No	$6,358	$5,171	$2,700	No	12/31/2014
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2013	Yellow as of 4/30/2012	Implemented	1,041	2,771	1,469	No	4/27/2014
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2013	Red as of 6/30/2012	Implemented	1,284	1,093	1,331	No	11/30/2014
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2013	Red as of 2/29/2012	Implemented	1,489	564	722	No	8/31/2015
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2013	Yellow as of 5/31/2012	Implemented	921	567	628	No	6/30/2016
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	5,883	5,603	4,841	No	5/31/2012*–8/31/2017
OE Pension Trust Fund	94-6090764-001	Yellow	Yellow as of 12/31/2012	Implemented	1,510	1,156	1,367	No	6/30/2013*–3/31/2016
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming	83-6011320-001	Red as of 12/31/2013	Red as of 12/31/2012	Implemented	76	91	96	No	10/31/2005*
Operating Engineers Pension Trust	95-6032478-001	Red as of 6/30/2013	Red as of 6/30/2012	Implemented	493	761	458	No	7/1/2013*–7/20/2014
Pension and Retirement Plan of Plumbers and Pipefitters Union Local	88-6003864-001	Green as of 6/30/2012	Green as of 6/30/2011	No	1,657	1,202	759	No	5/31/2010*

No. 525 Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Red as of 12/31/2013	Red as of 12/31/2012	Implemented	512	467	336	No	6/30/2014
Other funds					18,036	15,333	14,451		
Total contributions					$39,260	$34,779	$29,158		

* Plan includes collective bargaining agreements which have expired. The agreements contain provisions that automatically renew the existing contracts in lieu of a new negotiated collective bargaining agreement.

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

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Edison Pension Plan	2012 and 2011
IBEW Local 38 Pension Plan	2012 and 2011
IBEW Local No. 82 Pension Plan	2012 and 2011
Local Union No. 124 IBEW Pension Trust Fund	2012 and 2011
Local Union 212 IBEW Pension Trust Fund	2012 and 2011
IBEW Local Union No. 357 Pension Plan A	2012 and 2011
IBEW Local 648 Pension Plan	2012 and 2011
Idaho Plumbers and Pipefitters Pension Plan	2012 and 2011
Minnesota Teamsters Construction Division Pension Fund	2012 and 2011
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming	2012 and 2011
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	2012 and 2011

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $37.1 million, $31.4 million and $24.0 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Amounts contributed in 2013, 2012 and 2011 to defined contribution multiemployer plans were $20.6 million, $18.7 million and $15.3 million, respectively.

Note 17 - Jointly Owned Facilities

The consolidated financial statements include the Company's ownership interests in the assets, liabilities and expenses of the Big Stone Station, Coyote Station and Wygen III. Each owner of the stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses (fuel, operation and maintenance and taxes, other than income) in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2013	2012
	(In thousands)	
Big Stone Station:		
Utility plant in service	$63,890	$63,146
Less accumulated depreciation	41,323	40,859
	$22,567	$22,287
Coyote Station:		
Utility plant in service	$138,261	$135,073
Less accumulated depreciation	89,528	87,524

	$48,733	$47,549
Wygen III:		
Utility plant in service	$64,332	$63,462
Less accumulated depreciation	4,639	3,368
	$59,693	$60,094

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Note 18 - Regulatory Matters and Revenues Subject to Refund
On September 26, 2012, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total increase of $3.5 million annually or approximately 5.9 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, an operations building, automated meter reading and a new customer billing system. Montana-Dakota requested an interim increase, subject to refund, of $1.7 million or approximately 2.9 percent. On April 12, 2013, the MTPSC issued an interim order authorizing an interim increase of $850,000 annually to be effective with service rendered on or after April 15, 2013, subject to refund. A hearing was held August 5-6, 2013. On December 5, 2013, Montana-Dakota and the Montana Consumer Counsel filed a stipulation with the MTPSC with an increase of $1.5 million annually. On December 12, 2013, the MTPSC approved the stipulation to be effective with service rendered on or after December 15, 2013.

On February 11, 2013, Montana-Dakota filed an application with the NDPSC for approval of an environmental cost recovery rider for recovery of Montana-Dakota's share of the costs resulting from the environmental retrofit required to be installed at the Big Stone Station. The costs proposed to be recovered are associated with the ongoing construction costs for the installation of the BART air-quality control system. On February 27, 2013, the NDPSC suspended the filing pending further review. On May 31, 2013, Montana-Dakota filed revisions to its filing to reflect revised budget amounts. A hearing was held on September 16, 2013. On December 18, 2013, the NDPSC approved the environmental cost recovery rider tariff and adjustment.

On September 18, 2013, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase. Montana-Dakota requested a total increase of $6.8 million annually or approximately 6.4 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, an operations building, automated meter reading and a new customer billing system. Montana-Dakota requested an interim increase, subject to refund, of $4.5 million or approximately 4.2 percent. On October 9, 2013, the NDPSC approved the interim increase to be effective with service rendered on or after November 17, 2013. On October 23, 2013, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement that resolved the revenue requirement portion of the application and reflected a natural gas rate increase of $4.3 million annually or approximately 4.0 percent, and agreed that Montana-Dakota will only implement $4.3 million of interim rate relief. The NDPSC held an informal hearing on the settlement on November 13, 2013. Montana-Dakota implemented the interim rate increase of $4.3 million effective with service rendered on or after November 17, 2013. On December 30, 2013, the NDPSC approved the settlement on the revenue requirement. A hearing on the rate design portion of the case was held February 5, 2014.

On October 31, 2013, WBI Energy Transmission filed a general natural gas rate change application with the FERC for an increase of $28.9 million annually to cover increased investments of $312 million, increased operating costs, and the effect of lower storage and off system volumes. WBI Energy Transmission will begin collecting the requested rates effective May 1, 2014, subject to refund.

Note 19 - Commitments and Contingencies
The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $29.5 million and $22.5 million for contingencies, including litigation, production taxes, royalty claims and environmental matters as of December 31, 2013 and 2012, respectively, which include amounts that may have been

accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association seeking compensatory damages of $149.7 million. An arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award was recorded in discontinued operations on the Consolidated Statement of Income in the fourth quarter of 2011. CEM filed a petition with the New York Supreme Court to vacate the arbitration award in favor of LPP. On October 19, 2012, Centennial moved to intervene in the New York Supreme Court action to vacate the arbitration award and also filed a complaint with the New York Supreme Court seeking a declaration that LPP is not entitled to indemnification from Centennial under the guaranty for the arbitration award. The New York Supreme Court granted CEM's petition to vacate the arbitration award on November 20, 2012, and entered an order and judgment to that effect on June 5, 2013. LPP appealed the order and judgment and on February 20, 2014, the New York Supreme Court Appellate Division ruled the arbitration award was properly vacated. Due to the vacation of the arbitration award, the Company no longer believes the loss related to this matter to be probable and thus the liability that was previously recorded in 2011 was reversed in the fourth quarter of 2012. The effect of this was recorded in discontinued operations on the Consolidated Statement of Income. For more information regarding discontinued operations, see Note 3.

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

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

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

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

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

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

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

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

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

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

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

The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.3 million for remediation of this site. In January 2013, the OPUC approved Cascade's application to defer environmental remediation costs at the Eugene site for a period of 12 months starting November 30, 2012. Cascade received an order reauthorizing the deferred accounting for the 12 months starting November 30, 2013.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.0 million for the remedial investigation, feasibility study and remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

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

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

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2013, were $32.8 million in 2014, $26.6 million in 2015, $22.2 million in 2016, $17.8 million in 2017, $13.5 million in 2018 and $45.7 million thereafter. Rent expense was $48.1 million, $42.9 million and $40.7 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Purchase commitments

The Company has entered into various commitments, largely construction, natural gas and coal supply, purchased power, natural gas transportation and storage, service, shipping and construction materials supply contracts, some of which are subject to variability in volume and price. These commitments range from one to 47 years. The commitments under these contracts as of December 31, 2013, were $635.8 million in 2014, $281.6 million in 2015, $170.7 million in 2016, $100.3 million in 2017, $73.4 million in 2018 and $910.8 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2013, 2012 and 2011, were $861.8 million, $718.4 million and $626.3 million, respectively.

Guarantees

Centennial guaranteed CEM's obligations under a construction contract. For more information, see Litigation in this note.

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

WBI Holdings has guaranteed certain of Fidelity's oil and natural gas swap agreement obligations. There is no fixed maximum amount guaranteed in relation to the oil and natural gas swap agreements as the amount of the obligation is dependent upon oil and natural gas commodity prices. The amount of derivative activity entered into by the subsidiary is limited by corporate policy. The guarantees of the oil and natural gas swap agreements at December 31, 2013, expire in the years ranging from 2014 to 2015; however, Fidelity continues to enter into additional derivative instruments and, as a result, WBI Holdings from time to time may issue additional guarantees on these derivative instruments. The amount outstanding by Fidelity was $4.8 million and was reflected on the Consolidated Balance Sheet at December 31, 2013. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At December 31, 2013, the fixed maximum amounts guaranteed under these agreements aggregated $54.4 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $32.5 million in 2014; $2.1 million in 2015; $700,000 in 2016; $600,000 in 2017; $500,000 in 2018; $500,000 in 2019; $13.5 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $200,000 and was reflected on the Consolidated Balance Sheet at December 31, 2013. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2013, the fixed maximum amounts guaranteed under these letters of credit, aggregated $36.0 million and are scheduled to expire in 2014. There were no amounts outstanding under the above letters of credit at December 31, 2013.

WBI Holdings has an outstanding guarantee to WBI Energy Transmission. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2013, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $800,000. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2013, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2013.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2013, approximately $516 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities
The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary. For more information, see Note 1.

Dakota Prairie Refining, LLC On February 7, 2013, WBI Energy and Calumet formed a limited liability company, Dakota Prairie Refining, and entered into an operating agreement to develop, build and operate Dakota Prairie Refinery in southwestern North Dakota. WBI Energy and Calumet each have a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of

$300 million, under the agreement are $150 million and $75 million, respectively. Capital commitments in excess of $300 million are expected to be shared equally between WBI Energy and Calumet. The total project cost is currently estimated at $350 million. Dakota Prairie Refining entered into a term loan for project debt financing of $75 million on April 22, 2013. The operating agreement provides for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt will be allocated to Calumet. Calumet's future cash distributions from Dakota Prairie Refining will be decreased by the principal and interest to be paid on the project debt, while the cash distributions to WBI Energy will not be decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan.

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

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

	2013 (In thousands)
Assets	
Current assets:	
Cash and cash equivalents	$4,774
Other current assets	26
Total current assets	4,800
Net property, plant and equipment	172,073
Total assets	$176,873
Liabilities	
Current liabilities:	
Long-term debt due within one year	$3,000
Accounts payable	8,904
Taxes payable	5
Accrued compensation	26
Other accrued liabilities	461
Total current liabilities	12,396
Long-term debt	72,000
Total liabilities	$84,396

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

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

At December 31, 2013, Coyote Creek was not yet operational. The assets and liabilities of Coyote Creek and exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage, at December 31, 2013, was $7.7 million.

Note 20 - Subsequent Event
On January 28, 2014, the Company entered into a note purchase agreement. The Company contracted to issue $50.0 million and $100.0 million of Senior Notes under the agreement on April 15, 2014 and July 15, 2014, respectively, with due dates ranging from July 2024 to April 2044 at a weighted average interest rate of 4.6 percent.

On December 12, 2013, MDU Energy Capital entered into a note purchase agreement. MDU Energy Capital contracted to issue $30.0 million of Senior Notes under the agreement on January 27, 2014, with due dates ranging from January 2029 to January 2044 at a weighted average interest rate of 5.3 percent.

On February 10, 2014, the Company 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 for approximately $183.0 million, subject to accounting and purchase price adjustments customary with acquisitions of this type. The effective date of the acquisition is October 1, 2013, with the expected closing date to occur on or before April 1, 2014, conditioned upon completing a due diligence process, including environmental reviews, and satisfying other standard closing conditions.

Supplementary Financial Information
Quarterly Data (Unaudited)
The following unaudited information shows selected items by quarter for the years 2013 and 2012:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2013				
Operating revenues	$931,604	$1,060,595	$1,285,782	$1,184,423
Operating expenses	827,073	969,217	1,135,909	1,037,306
Operating income	104,531	91,378	149,873	147,117
Income from continuing operations	56,592	46,392	84,550	91,348
Loss from discontinued operations, net of tax	(77)	(59)	(118)	(58)
Net income attributable to the Company	56,515	46,512	84,456	91,450
Earnings per common share - basic:				
Earnings before discontinued operations	.30	.25	.45	.48
Discontinued operations, net of tax	—	—	—	—
Earnings per common share - basic	.30	.25	.45	.48
Earnings per common share - diluted:				
Earnings before discontinued operations	.30	.24	.44	.48
Discontinued operations, net of tax	—	—	—	—
Earnings per common share - diluted	.30	.24	.44	.48
Weighted average common shares outstanding:				
Basic	188,831	188,831	188,831	188,929
Diluted	189,222	189,463	189,638	189,766
2012				
Operating revenues	$852,807	$967,962	$1,173,518	$1,081,144
Operating expenses	781,750	876,248	1,207,553	1,190,673
Operating income (loss)	71,057	91,714	(34,035)	(109,529)
Income (loss) from continuing operations	35,890	49,007	(29,532)	(69,686)
Income (loss) from discontinued operations, net of tax	(100)	5,106	(139)	8,700
Net income (loss) attributable to the Company	35,790	54,113	(29,671)	(60,986)
Earnings per common share - basic:				
Earnings (loss) before discontinued operations	.19	.26	(.16)	(.37)
Discontinued operations, net of tax	—	.03	—	.05
Earnings (loss) per common share - basic	.19	.29	(.16)	(.32)
Earnings (loss) per common share - diluted:				
Earnings (loss) before discontinued operations	.19	.26	(.16)	(.37)
Discontinued operations, net of tax	—	.03	—	.05
Earnings (loss) per common share - diluted	.19	.29	(.16)	(.32)
Weighted average common shares outstanding:				
Basic	188,811	188,831	188,831	188,831
Diluted	189,182	189,107	188,831	188,831

Notes:

- First quarter 2013 reflects an unrealized loss on commodity derivatives of $3.7 million (after tax). First quarter 2012 reflects an unrealized loss on commodity derivatives of $2.6 million (after tax).
- Second quarter 2013 reflects an impairment of coalbed natural gas gathering assets of $9.0 million (after tax) and an unrealized gain on commodity derivatives of $8.2 million (after tax). Second quarter 2012 reflects a net benefit of $15.0 million (after tax) related to natural gas gathering operations litigation, a net benefit largely related to estimated insurance recoveries related to the guarantee of a construction contract (reflected in income (loss) from discontinued

operations), an unrealized gain on commodity derivatives of $3.0 million (after tax) and an impairment of coalbed natural gas gathering assets of $1.7 million (after tax). For more information, see Notes 1 and 19.

- Third quarter 2013 reflects an unrealized loss on commodity derivatives of $7.9 million (after tax). Third quarter 2012 reflects a $100.9 million (after tax) noncash write-down of oil and natural gas properties and an unrealized loss on commodity derivatives of $700,000 (after tax). For more information, see Note 1.
- Fourth quarter 2013 reflects a net benefit of $1.5 million (after tax) related to natural gas gathering operations litigation and an unrealized loss on commodity derivatives of $500,000 (after tax). Fourth quarter 2012 reflects a $145.9 million (after tax) noncash write-down of oil and natural gas properties, the reversal of an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract, which was partially offset by the reversal of estimated insurance recoveries (reflected in income (loss) from discontinued operations), as well as an unrealized loss on commodity derivatives of $200,000 (after tax). For more information, see Notes 1 and 19.

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

Exploration and Production Activities (Unaudited)
Fidelity is involved in the acquisition, exploration, development and production of oil and natural gas resources. Fidelity shares revenues and expenses from the development of specified properties in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States in proportion to its ownership interests.

The information that follows includes Fidelity's proportionate share of all its oil and natural gas interests.

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

	2013	2012	2011
	(In thousands)		
Subject to amortization	$2,893,010	$2,531,562	$2,345,114
Not subject to amortization	124,869	191,794	232,462
Total capitalized costs	3,017,879	2,723,356	2,577,576
Less accumulated depreciation, depletion and amortization	1,562,116	1,383,386	1,229,654
Net capitalized costs	$1,455,763	$1,339,970	$1,347,922

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

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

Years ended December 31,	2013	*	2012	*	2011	*
	(In thousands)					
Acquisitions:						
Proved properties	$1,817		$839		$3,999	
Unproved properties	4,608		31,109		63,354	
Exploration	26,975		235,906		41,775	
Development	355,421		275,959		161,647	
Total capital expenditures	$388,821		$543,813		$270,775	

* Excludes net additions/(reductions) to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of oil and natural gas wells, as discussed in Note 10, of $(10.7) million, $(200,000) and $(1.8) million for the years ended December 31, 2013, 2012 and 2011, respectively.

The preceding table excludes proceeds from the sales of oil and natural gas properties of $83.6 million, $6.0 million and $12.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

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

Years ended December 31,	2013	2012	2011
	(In thousands)		
Revenues:			
Sales to affiliates	$45,099	$35,966	$93,713
Sales to external customers	497,018	379,647	348,428
Realized gain on commodity derivatives	173	33,628	9,618
Unrealized gain (loss) on commodity derivatives	(6,267)	(624)	1,827
Production costs	144,136	134,795	140,606
Depreciation, depletion and amortization*	182,352	157,078	139,539
Write-downs of oil and natural gas properties	—	391,800	—
Pretax income (loss)	209,535	(235,056)	173,441
Income tax expense (benefit)	75,836	(88,612)	63,655
Results of operations for producing activities	$133,699	$(146,444)	$109,786

* Includes accretion of discount for asset retirement obligations of $3.6 million, $3.3 million and $3.6 million for the years ended December 31, 2013, 2012 and 2011, respectively, as discussed in Note 10.

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The proved reserve estimates as of December 31, 2013, 2012 and 2011, were calculated using SEC Defined Prices. Other factors used in the proved reserve estimates are current estimates of well operating and future development costs (which include asset retirement costs), taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

The reserve estimates are prepared by internal engineers assigned to an asset team by geographic area. Senior management reviews and approves the reserve estimates to ensure they are materially accurate. In addition, the Company engaged Ryder Scott, an independent third party, to audit its proved reserve quantity estimates.

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

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

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

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	33,453	7,153	239,278	80,486
Production	(4,815)	(781)	(28,008)	(10,264)
Extensions and discoveries	13,313	1,333	26,428	19,050
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(1,286)	(25)	(40,055)	(7,987)

Revisions of previous estimates	354	(1,078)	802	(590)
Balance at end of year	41,019	6,602	198,445	80,695

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

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

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

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

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

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

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2011, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	25,666	7,201	448,397	107,599
Production	(2,724)	(776)	(45,598)	(11,099)
Extensions and discoveries	4,717	1,421	28,221	10,842
Improved recovery	—	—	—	—
Purchases of proved reserves	223	16	54	247
Sales of proved reserves	—	—	—	—
Revisions of previous estimates	(877)	(520)	(51,247)	(9,938)
Balance at end of year	27,005	7,342	379,827	97,651

Significant changes in proved reserves for the year ended December 31, 2011, include:

- Extensions and discoveries of 10.8 MMBOE primarily due to drilling activity at the Company's Bakken and Big Horn properties
- Revisions of previous estimates of (9.9) MMBOE, largely the result of a reduction in PUD reserves of 8.9 MMBOE resulting principally in the Company's Bowdoin, Baker, Coalbed, East Texas and Big Horn Basin properties. The remaining negative revisions were a reduction in PDP natural gas reserves.

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

	2013	2012	2011
Proved developed reserves:			
Oil (MBbls)	31,394	27,412	23,653
NGL (MBbls)	5,322	5,342	5,225
Natural Gas (MMcf)	176,546	218,259	303,495
Total (MBOE)	66,140	69,131	79,460
PUD reserves:			
Oil (MBbls)	9,625	6,041	3,352
NGL (MBbls)	1,280	1,811	2,117
Natural Gas (MMcf)	21,899	21,019	76,332
Total (MBOE)	14,555	11,355	18,191
Total proved reserves:			
Oil (MBbls)	41,019	33,453	27,005
NGL (MBbls)	6,602	7,153	7,342
Natural Gas (MMcf)	198,445	239,278	379,827
Total (MBOE)	80,695	80,486	97,651

As of December 31, 2013, the Company had 14.6 MMBOE of PUD reserves, which is an increase of 3.2 MMBOE from December 31, 2012. The increase relates to the Company adding 11.9 MMBOE of new PUD reserves, primarily in the Company's oil properties. This was partially offset by the Company converting 7.1 MMBOE, requiring $127.3 million of drilling and completion capital in 2013 and PUD revision of (1.6) MMBOE. At December 31, 2013, the Company did not have any PUD locations that remained undeveloped for five years or more. Future development costs estimated to be spent in each of the next three years to develop PUD reserves as of December 31, 2013, are $143.6 million in 2014, $116.0 million in 2015 and $18.1 million in 2016.

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

	2013	2012	2011
	(In thousands)		
Future cash inflows	$4,507,000	$3,696,200	$4,188,000
Future production costs	1,734,800	1,536,500	1,560,300
Future development costs	403,000	301,600	285,300
Future net cash flows before income taxes	2,369,200	1,858,100	2,342,400
Future income tax expense	545,200	304,900	531,100
Future net cash flows	1,824,000	1,553,200	1,811,300
10% annual discount for estimated timing of cash flows	810,000	669,800	832,500
Discounted future net cash flows relating to proved oil, NGL and natural gas reserves	$1,014,000	$883,400	$978,800

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

	2013	2012	2011
	(In thousands)		
Beginning of year	$883,400	$978,800	$896,100
Net revenues from production	(398,000)	(280,800)	(301,500)
Net change in sales prices and production costs related to future production	162,200	(406,300)	82,300
Extensions and discoveries, net of future production-related costs	366,500	355,300	226,300
Improved recovery, net of future production-related costs	—	—	—
Purchases of proved reserves, net of future production-related costs	—	—	9,500
Sales of proved reserves	(37,800)	(2,600)	—
Changes in estimated future development costs	6,700	37,600	51,100
Development costs incurred during the current year	141,500	77,700	56,300
Accretion of discount	94,600	121,400	105,000
Net change in income taxes	(141,400)	110,000	(55,800)
Revisions of previous estimates	(55,800)	(100,700)	(92,900)
Other	(7,900)	(7,000)	2,400
Net change	130,600	(95,400)	82,700
End of year	$1,014,000	$883,400	$978,800

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

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of oil and natural gas properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of oil, NGL and natural gas prices over the remaining reserve lives may vary significantly from SEC Defined Prices.

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

None.

Item 9A. Controls and Procedures

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

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The

Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in Internal Controls
No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2013, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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

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

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

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

Item 11. Executive Compensation

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

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

Equity Compensation Plan Information
The following table includes information as of December 31, 2013, with respect to the Company's equity compensation plans:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights		(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	
Equity compensation plans approved by stockholders (1)	749,991	(2)	$21.99	6,176,556	(3)(4)
Equity compensation plans not approved by stockholders	N/A		N/A	N/A	

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan, the Long-Term Performance-Based Incentive Plan and the Non-Employee Director Stock Compensation Plan.
(2) Consists of performance shares.
(3) 357,757 shares remain available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan in connection with grants of restricted stock, performance units, performance shares or other equity-based awards. 5,643,041 shares under the Long-Term Performance-Based Incentive Plan remain available for future issuance in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.
(4) This amount also includes 175,758 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors are awarded shares equal in value to $110,000 annually. A non-employee director may acquire additional shares under the plan in lieu of receiving the cash portion of the director's retainer or fees.

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

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

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

Item 14. Principal Accountant Fees and Services

The information required by this item is included under the caption "Accounting and Auditing Matters" in the Proxy Statement, which information is incorporated herein by reference.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

The following consolidated financial statements required under this item are included under Item 8 - Financial Statements and Supplementary Data.	Page
Consolidated Statements of Income for each of the three years in the period ended December 31, 2013	62
Consolidated Statements of Comprehensive Income for each of the three years in the period ended December 31, 2013	63
Consolidated Balance Sheets at December 31, 2013 and 2012	64
Consolidated Statements of Equity for each of the three years in the period ended December 31, 2013	65
Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2013	66
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2. Financial Statement Schedules

The following financial statement schedules are included in Part IV of this report.	Page
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)	
Condensed Statements of Income and Comprehensive Income for each of the three years in the period ended December 31, 2013	122
Condensed Balance Sheets at December 31, 2013 and 2012	123
Condensed Statements of Cash Flows for each of the three years in the period ended December 31, 2013	124
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MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Income and Comprehensive Income

Years ended December 31,	2013	2012	2011
	(In thousands)		
Operating revenues	$549,239	$472,302	$518,268
Operating expenses	473,917	405,095	450,579
Operating income	75,322	67,207	67,689
Other income	3,709	3,925	2,710
Interest expense	17,386	17,297	18,660
Income before income taxes	61,645	53,835	51,739
Income taxes	13,520	11,798	10,476
Equity in earnings (loss) of subsidiaries	230,808	(42,791)	171,763
Net income (loss) attributable to the Company	278,933	(754)	213,026
Dividends declared on preferred stocks	685	685	685
Earnings (loss) on common stock	$278,248	$(1,439)	$212,341
Comprehensive income (loss)	$289,449	$(2,474)	$197,286

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

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

December 31,	2013	2012
(In thousands, except shares and per share amounts)		
Assets		
Current assets:		
Cash and cash equivalents	$5,051	$3,596
Receivables, net	88,529	89,238
Accounts receivable from subsidiaries	31,372	2,957
Inventories	29,312	41,469
Deferred income taxes	3,196	3,685
Prepayments and other current assets	14,231	9,120
Total current assets	171,691	150,065
Investments	60,687	52,123
Investment in subsidiaries	2,380,829	2,253,294
Property, plant and equipment	1,785,861	1,581,776
Less accumulated depreciation, depletion and amortization	660,693	621,623
Net property, plant and equipment	1,125,168	960,153
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	121,253	155,483
Total deferred charges and other assets	126,065	160,295
Total assets	$3,864,440	$3,575,930
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$109	$108
Accounts payable	45,282	42,149
Accounts payable to subsidiaries	4,839	6,423
Taxes payable	12,337	12,399
Dividends payable	33,737	171
Accrued compensation	16,076	10,282
Other accrued liabilities	28,042	29,490
Total current liabilities	140,422	101,022
Long-term debt	434,598	356,760
Deferred credits and other liabilities:		
Deferred income taxes	205,639	172,769
Other liabilities	260,617	297,131
Total deferred credits and other liabilities	466,256	469,900
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	15,000	15,000
Common stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 189,868,780 shares in 2013 and 189,369,450 shares in 2012	189,869	189,369
Other paid-in capital	1,056,996	1,039,080
Retained earnings	1,603,130	1,457,146

Accumulated other comprehensive loss	(38,205)	(48,721)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,808,164	2,633,248
Total stockholders' equity	2,823,164	2,648,248
Total liabilities and stockholders' equity	$3,864,440	$3,575,930

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

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

Years ended December 31,	2013	2012	2011
	(In thousands)		
Net cash provided by operating activities	$188,259	$225,968	$217,514
Investing activities:			
Capital expenditures	(211,013)	(150,337)	(74,580)
Net proceeds from sale or disposition of property and other	20,624	1,120	720
Investments in and advances to subsidiaries	(1,016)	(1,387)	(5,701)
Investments from and advances from subsidiaries	10,000	5,000	—
Investments	613	12	—
Net cash used in investing activities	(180,792)	(145,592)	(79,561)
Financing activities:			
Repayment of short-term borrowings	—	—	(20,000)
Issuance of long-term debt	77,924	76,000	—
Repayment of long-term debt	(85)	(21)	(107)
Proceeds from issuance of common stock	14,554	88	5,744
Dividends paid	(98,405)	(159,768)	(123,323)
Excess tax benefit on stock-based compensation	—	21	358
Net cash used in financing activities	(6,012)	(83,680)	(137,328)
Increase (decrease) in cash and cash equivalents	1,455	(3,304)	625
Cash and cash equivalents - beginning of year	3,596	6,900	6,275
Cash and cash equivalents - end of year	$5,051	$3,596	$6,900

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

Notes to Condensed Financial Statements
Note 1 - Summary of Significant Accounting Policies
Basis of presentation The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, which is comprised of MDU Resources Group, Inc. (the Company) and Montana-Dakota and Great Plains, public utility divisions of the Company. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income (loss) from subsidiaries is reported as equity in earnings (loss) of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. In Schedule I, amounts from discontinued operations have not been separately stated. These statements should be read in conjunction with the consolidated financial statements and notes thereto of MDU Resources Group, Inc.

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

Note 2 - Debt The Company has long-term debt obligations outstanding of $434.7 million at December 31, 2013, with annual maturities of $100,000 in 2014, $100,000 in 2015, $50.1 million in 2016, $79.0 million in 2017, $100.0 million in 2018 and $205.4 million scheduled to mature in years after 2018.

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

Note 3 - Dividends The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $77.6 million, $125.8 million and $96.1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

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

For the years ended December 31, 2013, 2012 and 2011

Description	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Other *	Deductions **	Balance at End of Year
	(In thousands)				
Allowance for doubtful accounts:					
2013	$10,818	$5,725	$1,395	$7,853	$10,085
2012	12,407	7,064	1,754	10,407	10,818
2011	15,284	3,977	2,112	8,966	12,407

* Recoveries.
** Uncollectible accounts written off.

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

3. Exhibits

3(a)	Restated Certificate of Incorporation of the Company, as amended, dated May 13, 2010, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*
3(b)	Company Bylaws, as amended and restated, on March 4, 2013, filed as Exhibit 3 to Form 10-Q for the quarter ended March 31, 2013, filed on May 7, 2013, in File No. 1-3480*
4(a)	Indenture, dated as of December 15, 2003, between the Company and The Bank of New York, as trustee, filed as Exhibit 4(f) to Form S-8 on January 21, 2004, in Registration No. 333-112035*
4(b)	First Supplemental Indenture, dated as of November 17, 2009, between the Company and The Bank of New York Mellon, as trustee, filed as Exhibit 4(c) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*
4(c)	Centennial Energy Holdings, Inc. Master Shelf Agreement, dated April 29, 2005, among Centennial Energy Holdings, Inc. and the Prudential Insurance Company of America, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*
4(d)	Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*
4(e)	MDU Resources Group, Inc. Credit Agreement, dated May 26, 2011, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4(e) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*
4(f)	First Amendment to Credit Agreement, dated October 4, 2012, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4 to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*
4(g)	Centennial Energy Holdings, Inc. Credit Agreement, dated June 8, 2012, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto, filed as Exhibit 4 to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*
4(h)	MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC and the Prudential Insurance Company of America, filed as Exhibit 4 to Form 8-K dated August 16, 2007, filed on August 16, 2007, in File No. 1-3480*
4(i)	Amendment No. 1 to Master Shelf Agreement, dated October 1, 2008, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America, and the holders of the notes thereunder, filed as Exhibit 4(b) to Form 10-Q for the quarter ended September 30, 2008, filed on November 5, 2008, in File No. 1-3480*
4(j)	Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 8-K

	dated August 12, 1992, in File No. 1-7196*
4(k)	First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 10-Q for the quarter ended June 30, 1993, in File No. 1-7196*
4(l)	Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*
4(m)	Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*

+10(a)	Supplemental Income Security Plan, as amended and restated November 12, 2009, filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*
+10(b)	Director Compensation Policy, as amended May 16, 2013, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2013, filed on August 7, 2013, in File No. 1-3480*
+10(c)	Deferred Compensation Plan for Directors, as amended May 15, 2008, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2008, filed on August 7, 2008, in File No. 1-3480*
+10(d)	Non-Employee Director Stock Compensation Plan, as amended May 12, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*
+10(e)	MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*
+10(f)	Long-Term Performance-Based Incentive Plan, as amended November 17, 2011, filed as Exhibit 10(h) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*
+10(g)	MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended March 4, 2013, and Rules and Regulations, as amended March 4, 2013, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2013, filed on May 7, 2013, in File No. 1-3480*
+10(h)	Supplemental Executive Retirement Plan for John G. Harp, dated December 4, 2006, filed as Exhibit 10(ag) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*
+10(i)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended November 14, 2012, filed as Exhibit 10.1 to Form 8-K dated November 14, 2012, filed on November 20, 2012, in File No. 1-3480*
+10(j)	Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan as amended March 4, 2013, filed as Exhibit 10.2 to Form 8-K dated March 4, 2013, filed on March 7, 2013, in File No. 1-3480*
+10(k)	Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, filed as Exhibit 10.1 to Form 8-K dated August 12, 2010, filed on August 17, 2010, in File No. 1-3480*
+10(l)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of January 3, 2014**
+10(m)	Employment Letter for J. Kent Wells, dated March 9, 2011, filed as Exhibit 10(v) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*
+10(n)	MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as adopted November 17, 2011, filed as Exhibit 10(x) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*
+10(o)	MDU Resources Group, Inc. 401(k) Retirement Plan, as restated March 1, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*

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

+10(t)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated May 24, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*
+10(u)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*
+10(v)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*
+10(w)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 19, 2012, filed as Exhibit 10(z) to Form 10-K for the year ended December 31, 2012, filed on February 28, 2013, in File No. 1-3480*
+10(x)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*
+10(y)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(c) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*
+10(z)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 23, 2013, filed as Exhibit 10(d) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*
+10(aa)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 31, 2013**
+10(ab)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013**
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**
21	Subsidiaries of MDU Resources Group, Inc.**
23(a)	Consent of Independent Registered Public Accounting Firm**
23(b)	Consent of Ryder Scott Company, L.P.**
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

95	Mine Safety Disclosures**
99(a)	Ryder Scott Company, L.P. report dated January 27, 2014**
99(b)	Equity Distribution Agreement entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 1 to Form 8-K dated May 20, 2013, filed on May 20, 2013, in File No. 1-3480*
99(c)	First Amendment to Equity Distribution Agreement, dated December 2, 2013, entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC**

101	The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2013, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Equity, (v) the Consolidated Statements of Cash Flows, (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail, (vii) Schedule I - Condensed Financial Information of Registrant, tagged in summary and detail and (viii) Schedule II - Consolidated Valuation and Qualifying Accounts, tagged in summary and detail

* Incorporated herein by reference as indicated.
** Filed herewith.
\+ Management contract, compensatory plan or arrangement.

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

Signatures

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

MDU Resources Group, Inc.

Date:	February 21, 2014	By: /s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)

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

Signature	Title	Date
/s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)	Chief Executive Officer and Director	February 21, 2014
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 21, 2014
/s/ Nathan W. Ring Nathan W. Ring (Vice President, Controller and Chief Accounting Officer)	Chief Accounting Officer	February 21, 2014
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 21, 2014
/s/ Thomas Everist Thomas Everist	Director	February 21, 2014
/s/ Karen B. Fagg Karen B. Fagg	Director	February 21, 2014
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 21, 2014
/s/ A. Bart Holaday A. Bart Holaday	Director	February 21, 2014
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 21, 2014
/s/ Thomas C. Knudson Thomas C. Knudson	Director	February 21, 2014

/s/ William E. McCracken William E. McCracken	Director	February 21, 2014
/s/ Patricia L. Moss Patricia L. Moss	Director	February 21, 2014
/s/ J. Kent Wells J. Kent Wells	Director	February 21, 2014
/s/ John K. Wilson John K. Wilson	Director	February 21, 2014