MDU RESOURCES GROUP INC
Form 10-K
February 17, 2010

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

FORM 10-K

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

For the fiscal year ended December 31, 2009

OR

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

For the transition period from _____________ to ______________

Commission file number 1-3480

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

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

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

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x 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 x.

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 x 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 x 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. x

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 x.

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2009: $3,489,895,496.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 2, 2010: 187,863,394 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2010 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

Definitions

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
Alusa	Tecnica de Engenharia Electrica - Alusa
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
Bbl	Barrel
Bcf	Billion cubic feet
BER	Montana Board of Environmental Review
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Big Stone Station II	Formerly proposed coal-fired electric generating facility near Big Stone City, South Dakota (the Company had anticipated ownership of at least 116 MW)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Black Hills Power	Black Hills Power and Light Company
Brazilian Transmission Lines	Company's equity method investment in companies owning ECTE, ENTE and ERTE
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CBNG	Coalbed natural gas
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
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 International	Centennial Energy Resources International, Inc., a direct wholly owned subsidiary of Centennial Resources
Centennial Power	Centennial Power, Inc., a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
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

Company	MDU Resources Group, Inc.
D.C. Appeals Court	U.S. Court of Appeals for the District of Columbia Circuit
dk	Decatherm

ECTE	Empresa Catarinense de Transmissão de Energia S.A.
EIS	Environmental Impact Statement
ENTE	Empresa Norte de Transmissão de Energia S.A.
EPA	U.S. Environmental Protection Agency
ERTE	Empresa Regional de Transmissão de Energia S.A.
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
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
Hartwell	Hartwell Energy Limited Partnership, a former equity method investment of the Company (sold in the third quarter of 2007)
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
Indenture	Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York as Trustee
Innovatum	Innovatum, Inc., a former indirect wholly owned subsidiary of WBI Holdings (the stock and Innovatum's assets have been sold)
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital (acquired October 1, 2008)
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
Kennecott	Kennecott Coal Sales Company
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LTM	LTM, Inc., an indirect wholly owned subsidiary of Knife River
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
MAPP	Mid-Continent Area Power Pool
MBbls	Thousands of barrels
MBI	Morse Bros., Inc., an indirect wholly owned subsidiary of Knife River
MBOGC	Montana Board of Oil and Gas Conservation
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 International

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
MEIC	Montana Environmental Information Center, Inc.
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million Btu
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent - natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil
MMdk	Million decatherms
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana State Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Twenty-Second Judicial District Court	Montana Twenty-Second Judicial District Court, Big Horn County
Mortgage	Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustees
MPX	MPX Termoceara Ltda. (49 percent ownership, sold in June 2005)
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
North Dakota District Court	North Dakota South Central Judicial District Court for Burleigh County
NPRC	Northern Plains Resource Council
NSPS	New Source Performance Standards
Oil	Includes crude oil, condensate and natural gas liquids
OPUC	Oregon Public Utilities Commission
Order on Rehearing	Order on Rehearing and Compliance and Remanding Certain Issues for Hearing
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
PRP	Potentially Responsible Party
Proxy Statement	Company's 2010 Proxy Statement
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission

SEC Defined Prices	The average price of natural gas and oil 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
South Dakota Federal District Court	U.S. District Court for the District of South Dakota
South Dakota SIP	South Dakota State Implementation Plan
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
TRWUA	Tongue River Water Users' Association
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Westmoreland	Westmoreland Coal Company
Williston Basin	Williston Basin Interstate Pipeline Company, an indirect wholly owned subsidiary of WBI Holdings
WUTC	Washington Utilities and Transportation Commission
WYPSC	Wyoming Public Service Commission

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 products and services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (comprised of the pipeline and energy services and the natural gas and oil 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 equity method investment in the Brazilian Transmission Lines, as discussed in Item 8 – Note 4, is reflected in the Other category.

As of December 31, 2009, the Company had 8,081 employees with 158 employed at MDU Resources Group, Inc., 874 at Montana-Dakota, 31 at Great Plains, 329 at Cascade, 264 at Intermountain, 603 at WBI Holdings, 2,879 at Knife River and 2,943 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.

At Montana-Dakota and Williston Basin, 365 and 80 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through May 30, 2011, and March 31, 2011, for Montana-Dakota and Williston Basin, respectively.

At Cascade, 201 employees are represented by the ICWU. The labor contract with the field operations group, consisting of 169 employees, is effective through April 1, 2012. Cascade has an agreement with the bargaining unit consisting of 32 customer service representatives and credit and collections clerks in effect through March 19, 2011.

At Intermountain, 114 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2010.

Knife River has 43 labor contracts that represent approximately 440 of its construction materials employees. Knife River is in negotiations on five of its labor contracts.

MDU Construction Services has 126 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.

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 concern for reductions in GHG emissions and expansion of renewable energy resources has increased, the Company has placed an increasing emphasis on developing renewable generation resources. 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 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.

This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q, the Company's 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 122,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2009. The principal properties owned by Montana-Dakota for use in its electric operations include interests in nine electric generating facilities, as further described under System Supply, System Demand and Competition, and approximately 3,000 and 4,600 miles of transmission and distribution lines, respectively. 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. As of December 31, 2009, Montana-Dakota's net electric plant investment approximated $514.5 million.

The percentage of Montana-Dakota's 2009 retail electric utility operating revenues by jurisdiction is as follows: North Dakota – 58 percent; Montana – 24 percent; Wyoming – 11 percent; and South Dakota – 7 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. Montana-Dakota participates in the Midwest ISO wholesale energy and ancillary services market. The Midwest ISO is a regional transmission organization responsible for operational control of the transmission systems of its members. The Midwest ISO provides security center operations, tariff administration and operates day-ahead and real-time energy markets and an ancillary services market. As a member of Midwest ISO, Montana-Dakota's generation is sold into the Midwest ISO 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, Dickinson and Williston; eastern Montana, including Glendive and Miles City; and northern South

Dakota, including Mobridge. The interconnected system consists of nine electric generating facilities, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 463,055 kW and a total summer net capability of 486,900 kW. 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, aggregating 22.7 percent and 25.0 percent, respectively) is 327,758 kW. Three combustion turbine peaking stations, a wind electric generating facility and a heat recovery electric generating facility supply the balance of Montana-Dakota's interconnected system electric generating capability.

In September 2005, Montana-Dakota entered into a contract for seasonal capacity from a neighboring utility, starting at 85 MW in 2007, increasing to 105 MW in 2011, with an option for capacity in 2012. In April 2007, Montana-Dakota entered into a contract for seasonal capacity of 10 MW in May through October of each year continuing through 2010. In August 2009, Montana-Dakota entered into a contract for capacity of 110 MW, 115 MW and 120 MW annually for the three-year period from June 1 to May 31, 2013, 2014 and 2015, respectively. Energy also will be purchased as needed from the Midwest ISO market. In 2009, Montana-Dakota purchased approximately 17 percent of its net kWh needs for its interconnected system through the Midwest ISO market.

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

Generating Station	Type	Nameplate Rating (kW)	Summer Capability (kW)	2009 Net Generation (kWh in thousands)
North Dakota:				
Coyote*	Steam	103,647	106,750	625,979
Heskett	Steam	86,000	102,730	556,757
Williston	Combustion Turbine	7,800	9,600	(81) **
Glen Ullin	Heat Recovery	7,500	***	10,271
South Dakota:				
Big Stone*	Steam	94,111	107,500	624,595
Montana:				
Lewis & Clark	Steam	44,000	52,300	316,532
Glendive	Combustion Turbine	77,347	79,610	1,950
Miles City	Combustion Turbine	23,150	24,500	(28) **
Diamond Willow	Wind	19,500	3,910	67,690
		463,055	486,900	2,203,665

* Reflects Montana-Dakota's ownership interest.
** Station use, to meet MAPP's accreditation requirements, exceeded generation.
*** Pending accreditation.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland under contracts that expire in May 2016, April 2011 and December 2012, respectively. The Coyote 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 maximum quantity of coal during the term of the agreement, and any extension, is 75 million tons. 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 500,000 to 600,000 tons, and 250,000 to 350,000 tons per contract year, respectively.

Montana-Dakota has a coal supply agreement, which meets the majority of the Big Stone Station's fuel requirements, for the purchase of 1.0 million tons of coal in 2010 with Kennecott at contracted pricing.

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

Years ended December 31,	2009	2008	2007
Average cost of coal per MMBtu	$1.52	$1.49	$1.29
Average cost of coal per ton	$22.05	$21.45	$18.71

The maximum electric peak demand experienced to date attributable to sales to retail customers on the interconnected system was 525,643 kW in July 2007. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the peak demand growth rate through 2015 will approximate two percent annually.

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-2015. 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 contracts. For additional information regarding potential power generation projects, see Item 7 – MD&A – Prospective Information – Electric.

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.

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 60,600 kW in July 2007. Montana-Dakota has a power supply contract with Black Hills Power to purchase up to 74,000 kW of capacity annually through December 31, 2016. On April 9, 2009, Montana-Dakota exercised an option to purchase a 25 percent interest in the Wygen III electric generating facility under construction by Black Hills Power to serve a portion of the needs of its Sheridan-area customers. The plant is expected to be commercial in the second quarter of 2010, and will replace 25 MW of capacity and energy purchased under the power supply contract. Montana-Dakota received a Certificate of Public Convenience and Necessity from the WYPSC on July 29, 2008, for ownership of Wygen III.

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 Fuel adjustment clauses contained in North Dakota and South Dakota jurisdictional electric rate schedules allow Montana-Dakota to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In North Dakota, the Company is deferring electric fuel and purchased power costs (excluding demand charges) 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. In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota to reflect increases or decreases in fuel and purchased power costs (including demand charges) 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.

On August 14, 2009, Montana-Dakota filed an application with the WYPSC for an electric rate increase. For additional information, see Item 8 – Note 18.

In November 2009, a decision was made by the Big Stone Station II participants not to proceed with the project. For additional information, see Item 8 – Note 18.

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. Title V Operating Permits for the Big Stone Station and the Lewis & Clark Station were renewed in 2009. In August 2009, an application for renewal of the Heskett Station Title V Operating Permit was submitted. On February 25, 2009, a Montana Air Quality Permit application was granted for the Lewis & Clark Station to obtain a mercury emissions limit and approve its proposed mercury emissions control strategy.

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.

In June 2008, the Sierra Club filed a complaint in the South Dakota Federal District Court against Montana-Dakota and the two other co-owners of the Big Stone Station. For more information regarding this complaint, see Item 8 – Note 19.

Montana-Dakota incurred $5.9 million of environmental capital expenditures in 2009. Capital expenditures are estimated to be $1.7 million, $5.0 million and $6.5 million in 2010, 2011 and 2012, respectively, to maintain environmental compliance as new emission controls are required. Projects will include sulfur-dioxide, nitrogen oxide and mercury control equipment installation at electric generating stations. Montana-Dakota’s capital and operational expenditures could also 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 renewable energy resources 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 829,000 residential, commercial and industrial customers in 333 communities and adjacent rural areas across eight states as of December 31, 2009, and provide natural gas transportation services to certain customers on their systems. These services are provided through distribution systems aggregating approximately 17,000 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. As of December 31, 2009, the natural gas distribution operations' net natural gas distribution plant investment approximated $909.9 million.

The percentage of the natural gas distribution operations’ 2009 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho – 32 percent; Washington – 30 percent; North Dakota – 11 percent; Oregon – 9 percent; Montana – 7 percent; South Dakota – 6 percent; Minnesota – 3 percent; and Wyoming – 2 percent. The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of Idaho, including Boise, Nampa, Twin Falls, Pocatello and Idaho Falls; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; North Dakota, including Bismarck, Dickinson, Wahpeton, Williston, Minot and Jamestown; central and eastern Oregon, including Bend and Pendleton; western and north-central South Dakota, including Rapid City, Pierre, Spearfish and Mobridge; western, southeastern and south-central Washington, including Bellingham, Bremerton,

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Longview, 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.

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. Certain of these services include transportation under flexible rate schedules whereby interruptible customers can avail themselves of the advantages of open access transportation on regional transmission pipelines, including the systems of Williston Basin, Northern Border Pipeline Company, Northern Natural Gas Company, South Dakota Intrastate Pipeline, Viking Gas Transmission Company, Northwest Pipeline GP and Gas Transmission Northwest Corporation. 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 obtain their system requirements directly from producers, processors and marketers. Such natural gas is supplied by a portfolio of contracts specifying market-based pricing and is transported under transportation agreements by Williston Basin, South Dakota Intrastate Pipeline Company, Northern Border Pipeline Company, Viking Gas Transmission Company, Northern Natural Gas Company, Source Gas, TransCanada Foothills System, TransCanada NOVA System, Northwestern Energy, Northwest Pipeline GP, TransCanada Gas Transmission Northwest Corporation and Spectra Energy Transmission West. 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 Williston Basin, Northern Natural Gas Company, Questar Pipeline and Northwest Pipeline GP. In addition, certain of the operations have entered into natural gas supply management agreements with Sequent Energy Management, IGI Resources Inc. and Tenaska Gas Storage. 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.

Cascade has received approval for decoupling its margins from weather and conservation in Oregon, and has also received approval of a decoupling mechanism in Washington that allows it to recover margin differences resulting from customer conservation. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

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.

Natural gas distribution operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Certain 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. The natural gas distribution operations expect they 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.

The natural gas distribution operations did not incur any material environmental expenditures in 2009 and, except as to what may be ultimately determined with regard to the issues described later, do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations in relation to the natural gas distribution operations through 2012.

Montana-Dakota has had an economic interest in five historic manufactured gas plants within its service territory, none of which are currently being actively investigated, and for which any remediation expenses are not expected to be material. Cascade has had an economic interest in nine former manufactured gas plants within its service territory. Cascade has been involved with other PRPs in the investigation of a manufactured gas plant site in Oregon, with remediation of this site pending additional investigation. See Item 8 – Note 19 for a further discussion of this site and for two additional sites for which Cascade has received claim notice. 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.

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, 2009, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops. At December 31, 2009, MDU Construction Services' net plant investment was approximately $48.5 million.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2009, was approximately $383 million compared to $604 million at December 31, 2008. MDU Construction Services expects to complete a significant amount of this backlog during the year ending December 31, 2010. 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 customer's 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 2009 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2012.

Pipeline and Energy Services
General Williston Basin, the regulated business of WBI Holdings, owns and operates over 3,700 miles of transmission, gathering and storage lines and owns or leases and operates 33 compressor stations 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. Williston Basin's system is strategically located near five natural gas producing basins, making natural gas supplies available to Williston Basin's transportation and storage customers. The system has 11 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. At December 31, 2009, Williston Basin's net plant investment was approximately $287.3 million. Under the Natural Gas Act, as amended, Williston Basin is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters.

Bitter Creek, the nonregulated pipeline business, owns and operates gathering facilities in Colorado, Kansas, Montana and Wyoming. Bitter Creek also owns a one-sixth interest in the assets of various offshore gathering pipelines, an associated onshore pipeline and related processing facilities in Texas. In total, these facilities include over 1,900 miles of field gathering lines and 88 owned or leased compression stations, some of which interconnect with Williston Basin's system. In 2009, the Company acquired the assets of a cathodic protection company. This acquisition was not material to the Company. Bitter Creek also provides a variety of energy-related services such as water hauling, contract compression operations, measurement services and energy efficiency product sales and installation services to large end-users.

WBI Holdings, through its energy services business, 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 the Company's natural gas and oil production segment. Certain of the services are provided based on contracts that call for a determinable quantity of natural gas. WBI Holdings currently estimates that it can adequately meet the requirements of these contracts. WBI Holdings transacts a majority of its pipeline and energy services business in the northern Great Plains and Rocky Mountain regions of the United States.

System Demand and Competition Williston Basin 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 Williston Basin's system near five natural gas producing basins and the availability of underground storage and gathering services provided by Williston Basin and affiliates along with interconnections with other pipelines serve to enhance Williston Basin's competitive position.

Although certain of Williston Basin'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.

Williston Basin transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for the year ended December 31, 2009, represented 50 percent of Williston Basin's subscribed firm transportation contract demand. Montana-Dakota has firm transportation agreements with Williston Basin expiring November 2010 through June 2012. In addition, Montana-Dakota has a contract with Williston Basin to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements expiring in July 2015.

Bitter Creek competes with several pipelines for existing customers and for the expansion of its systems to gather natural gas in new areas. Bitter Creek's 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.

System Supply Williston Basin'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. The native gas includes an estimated 29 Bcf of recoverable gas. Williston Basin's storage facilities enable its customers to purchase natural gas at more uniform daily volumes throughout the year and meet winter peak requirements.

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 have helped support Williston Basin'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, including the Company's CBNG assets, also provides a nontraditional natural gas supply to the Williston Basin system. For additional information regarding CBNG legal proceedings, see Item 1A – Risk Factors and Item 8 – Note 19. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. Williston Basin expects to facilitate the movement of these supplies by making available its transportation and storage services. Williston Basin 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.

Regulatory Matters and Revenues Subject to Refund In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. For additional information, see Item 8 – Note 18.

Environmental Matters WBI Holdings' pipeline and energy services operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. WBI Holdings 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 Williston Basin and Bitter Creek 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 Williston Basin's natural gas transmission pipelines, compressor stations and storage facilities.

WBI Holdings' pipeline and energy services operations did not incur any material environmental expenditures in 2009 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2012.

Natural Gas and Oil Production

General Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties and leaseholds with potential development opportunities, exploratory drilling and the operation and development of natural gas and oil production properties. 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.

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

Rocky Mountain

Fidelity's properties in this region are primarily in Colorado, Montana, North Dakota, Utah and Wyoming. Fidelity owns in fee or holds natural gas and oil leases for the properties it operates that are in the Bonny Field in eastern Colorado, the Baker Field in southeastern Montana and southwestern North Dakota, the Bowdoin area in north-central Montana, the Powder River Basin of Montana and Wyoming, the Bakken area in North Dakota, the Paradox Basin of Utah, and the Big Horn Basin of Wyoming. Fidelity also owns nonoperated natural gas and oil interests and undeveloped acreage positions in this region.

Mid-Continent/Gulf States

This region includes properties in Alabama, Louisiana, New Mexico, Texas and the Offshore Gulf of Mexico. The Offshore Gulf of Mexico interests are primarily located in the shallow waters off the coasts of Texas and Louisiana. Fidelity owns in fee or holds natural gas and oil leases for the properties it operates that are in the Tabasco and Texan Gardens fields of Texas and natural gas properties in Rusk County in eastern Texas. In addition, Fidelity owns several nonoperated interests and undeveloped acreage positions in this region.

Operating Information Annual net production by region for 2009 was as follows:

Region	Natural Gas (MMcf)*	Oil (MBbls)	Total (MMcfe)	Percent of Total	
Rocky Mountain	41,635	2,182	54,729	73	%
Mid-Continent/Gulf States	14,997	929	20,570	27	
Total	56,632	3,111	75,299	100	%

* Baker field and Bowdoin field represent 28 percent and 19 percent, respectively, of total annual net natural gas production.

Annual net production by region for 2008 was as follows:

Region	Natural Gas (MMcf) *	Oil (MBbls)	Total (MMcfe)	Percent of Total	
Rocky Mountain	47,504	1,698	57,691	70	%
Mid-Continent/Gulf States	17,953	1,110	24,612	30	
Total	65,457	2,808	82,303	100	%

* Baker field and Bowdoin field represent 28 percent and 18 percent, respectively, of total annual net natural gas production.

Annual net production by region for 2007 was as follows:

Region	Natural Gas (MMcf) *	Oil (MBbls)	Total (MMcfe)	Percent of Total	
Rocky Mountain	48,832	1,287	56,553	74	%
Mid-Continent/Gulf States	13,966	1,078	20,435	26	
Total	62,798	2,365	76,988	100	%

* Baker field and Bowdoin field represent 31 percent and 19 percent, respectively, of total annual net natural gas production.

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, 2009, were as follows:

	Gross*	Net**
Productive wells:		
Natural gas	3,869	3,121
Oil	3,706	258
Total	7,575	3,379
Developed acreage (000's)	720	400
Undeveloped acreage (000's)	834	449

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

Exploratory and Development Wells The following table reflects activities related to Fidelity's natural gas and oil wells drilled and/or tested during 2009, 2008 and 2007:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2009	1	2	3	104	–	104	107
2008	11	4	15	251	9	260	275
2007	4	5	9	317	16	333	342

At December 31, 2009, there were 74 gross (60 net) wells in the process of drilling or under evaluation, 70 of which were development wells and 4 of which were exploratory wells. These wells are not included in the previous table. Fidelity expects to complete the drilling and testing of the majority 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 natural gas and oil industry is highly competitive. Fidelity competes with a substantial number of major and independent natural gas and oil 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 natural gas and oil production 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 and other state and federal 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 incurred certain capital expenditures related to water handling. For 2009, capital expenditures for water handling in compliance with current laws and regulations were approximately $222,000 and are estimated to be approximately $3.0 million, $8.9 million and $9.2 million in 2010, 2011 and 2012, respectively. These water handling costs are primarily related to the CBNG properties. For more information regarding CBNG litigation, see Item 1A – Risk Factors and Item 8 – Note 19.

Proved Reserve Information 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. Other factors used in the reserve estimates are prices, 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 reserve estimates are prepared by internal engineers assigned to an asset team by geographic area and are reviewed and approved by management. The technical person responsible for overseeing the preparation of the reserve estimates holds a bachelor of science degree in geological engineering, has substantial practical experience in petroleum engineering and reserve estimation, and is a member of multiple professional organizations. In addition, the Company engages an independent third party to audit its proved reserves. Ryder Scott Company, L.P. reviewed the Company's proved reserve quantity estimates as of December 31, 2009. The technical person at Ryder Scott Company, L.P. primarily responsible for overseeing the reserves

audit holds a bachelor of science degree in mechanical engineering, has extensive experience estimating and auditing reserves attributable to oil and gas properties, and is a member of multiple professional organizations.

Fidelity's recoverable proved reserves by region at December 31, 2009, are as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total		PV-10 Value* (in millions)
Rocky Mountain	309,359	24,354	455,482	70	%	$563.9
Mid-Continent/Gulf States	139,066	9,862	198,242	30		225.3
Total reserves	448,425	34,216	653,724	100	%	789.2
Discounted future income taxes						130.4
Standardized measure of discounted future net cash flows relating to proved reserves						$658.8

* 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 natural gas and oil 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 Company's 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 natural gas and oil properties.

For additional information related to natural gas and oil 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 liquid asphalt for various commercial and roadway applications; 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, 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 $459 million in backlog at December 31, 2009, compared to $453 million at December 31, 2008. The Company anticipates that a significant amount of the current backlog will be completed during the year ending December 31, 2010.

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 Reserve estimates are calculated based on the best available data. These data are collected from drill holes and other subsurface investigations, as well as investigations of surface features such as mine highwalls 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 above 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 2007 through 2009. 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, 2009, and sales for the years ended December 31, 2009, 2008 and 2007:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves (000's tons)	Lease	Reserve Life
Production Area	owned	leased	owned	leased	2009	2008	2007		Expiration	(years)
Anchorage, AK	-	-	1	-	891	1,267	1,118	17,554	N/A	16
Hawaii	-	6	-	-	1,940	2,467	3,081	63,622	2011-2064	25
Northern CA	-	-	9	1	1,215	2,054	2,534	49,393	2014	26
Southern CA	-	2	-	-	337	106	69	94,887	2035	Over 100
Portland, OR	1	3	6	3	2,718	4,074	5,372	248,243	2010-2055	61
Eugene, OR	3	4	4	1	1,097	1,633	2,007	172,258	2010-2046	Over 100
Central OR/WA/Idaho	1	2	4	3	1,436	1,686	2,652	107,632	2010-2021	56
Southwest OR	5	4	12	7	1,871	2,248	3,686	102,561	2011-2048	39
Central MT	-	-	3	2	1,220	2,086	2,424	27,136	2013-2027	14
Northwest MT	-	-	9	3	1,289	1,198	1,318	48,033	2010-2020	38
Wyoming	-	-	1	2	655	720	116	14,041	2013-2019	28
Central MN	-	1	38	33	1,868	1,367	2,639	83,549	2010-2028	43
Northern MN	2	-	17	6	838	333	753	28,262	2010-2016	44
ND/SD	-	-	2	24	699	876	943	39,428	2010-2031	47
Iowa	-	2	1	14	545	1,405	1,592	10,544	2010-2018	9
Texas	1	2	-	2	1,080	1,619	1,290	18,348	2010-2025	14
Sales from other sources					4,296	5,968	5,318			
					23,995	31,107	36,912	1,125,491		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2009, is comprised of 472 million tons that are owned and 653 million tons that are leased. Approximately 51 percent of the tons under lease have lease expiration dates of 20 years or more. The weighted average years remaining on all leases containing estimated probable aggregate reserves is approximately 22 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2007 through 2009 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 53 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 following table summarizes Knife River's aggregate reserves at December 31, 2009, 2008 and 2007, and reconciles the changes between these dates:

	2009	2008	2007
		(000's of tons)	
Aggregate reserves:			
Beginning of year	1,145,161	1,215,253	1,248,099
Acquisitions	21,400	27,650	29,740
Sales volumes*	(19,699)	(25,139)	(31,594)
Other**	(21,371)	(72,603)	(30,992)
End of year	1,125,491	1,145,161	1,215,253

* 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 what may be ultimately determined with regard to the Portland, Oregon, Harbor Superfund Site issue described later, Knife River believes it is in substantial compliance with these regulations. Individual permits applicable to Knife River's various operations are managed largely by local operations, particularly as they relate to application, modification, renewal, compliance, and reporting procedures.

Knife River's asphalt and ready-mixed concrete manufacturing plants and aggregate processing plants are subject to Clean Air Act and Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities also are subject to these laws. In most of the states where Knife River operates, these regulatory programs have been delegated to state and local regulatory authorities. Knife River's facilities also are subject to RCRA as it applies to the management of hazardous wastes and underground storage tank systems. These programs also have generally been delegated to the state and local authorities in the states where Knife River operates. Knife River's facilities must comply with requirements for managing wastes and underground storage tank systems.

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

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

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

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

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

Knife River's Gascoyne surface coal mine last produced coal in 1995 but continues to be subject to reclamation requirements of the SMCRA, as well as the North Dakota Surface Mining Act. Portions of the Gascoyne Mine remain under reclamation bond until the 10-year revegetation liability period has expired. A portion of the original permit has been released from bond and additional areas are currently in the process of having the bond released. Knife River's intention is to request bond release as soon as it is deemed possible with all final bond release applications being filed by 2013.

Knife River did not incur any material environmental expenditures in 2009 and, except as to what may be ultimately determined with regard to the issue described below, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2012.

In December 2000, MBI was named by the EPA as a PRP in connection with the cleanup of a commercial property site, acquired by MBI in 1999, and part of the Portland, Oregon, Harbor Superfund Site. For additional information, see Item 8 – Note 19.

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 natural gas and oil production and pipeline and energy services businesses are dependent on factors, including commodity prices and commodity price basis differentials, which are subject to various external influences that cannot be controlled.

These factors include: fluctuations in natural gas and oil prices; fluctuations in commodity price basis differentials; availability of economic supplies of natural gas; drilling successes in natural gas and oil 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 drill for and develop reserves; the ability to acquire natural gas and oil properties; and other risks incidental to the operations of natural gas and oil wells. Volatility in natural gas and oil prices could negatively affect the results of operations and cash flows of the Company's natural gas and oil production and pipeline and energy services businesses.

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

The construction, startup and operation of power generation facilities involve many risks, including: delays; breakdown or failure of equipment; competition; inability to obtain required governmental permits and approvals; inability to negotiate acceptable acquisition, construction, fuel supply, off-take, transmission or other material agreements; changes in market price for power; 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 and, as a result, may have a negative impact on the Company's future revenues and cash flows.

The global demand for natural resources, interest rates, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. The current economic slowdown has negatively affected the level of public and private expenditures on projects and the timing of these projects which, in turn, has negatively affected the demand for certain of the Company's products and services. Continued economic volatility could adversely impact the Company's results of operations and cash flows. 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 further 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
- Further deterioration in capital market conditions
- Turmoil in the financial services industry
- Volatility in commodity prices
- Terrorist attacks

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

The Company currently has authorization to issue and sell up to $1.0 billion of securities pursuant to a registration statement on file with the SEC. 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 any of 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 services and construction materials and contracting 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 natural gas and oil reserves and discounted future net cash flows from those reserves may vary significantly from estimated amounts.

The process of estimating natural gas and oil reserves is complex. Reserve estimates are based on assumptions relating to natural gas and oil pricing, drilling and operating expenses, capital expenditures, taxes, timing of operations, and the percentage of interest owned by the Company in the well. The 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 reserve estimates in accordance with guidelines established by the industry and the SEC, significant changes to the 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. Sustained downward movements in natural gas and oil prices could result in future noncash write-downs of the Company's natural gas and oil properties.

Environmental and Regulatory Risks
Some of the Company's operations are subject to extensive 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 extensive 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, and delays as a result of ongoing litigation and administrative proceedings and compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions and CBNG development. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Public officials and entities, as well as private individuals and organizations, may seek injunctive relief or other remedies to enforce applicable environmental laws and regulations. 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, require the installation of pollution control equipment or the initiation of pollution control technologies, remediate environmental contamination, remove or reduce environmental hazards, or prevent or limit the development of resources. Revised or additional laws and regulations, which 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 Company's electric generation operations could be adversely impacted by global climate change initiatives to reduce GHG emissions.

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 including the EPA’s proposed endangerment finding for GHGs which could lead to regulation of GHG under the Clean Air Act. 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 electric generating facilities which comprise more than 70 percent of Montana-Dakota’s generating capacity. More than 90 percent of the electricity generated by Montana-Dakota is from coal-fired plants and Montana-Dakota has acquired a 25 MW ownership interest in the Wygen III coal-fired generation facility which is under construction near Gillette, Wyoming. Montana-Dakota also owns approximately 100 MW of natural gas- and oil-fired peaking plants. While there are many uncertainties regarding the future of GHG regulation, Montana-Dakota’s electric generating facilities may be subject to regulation under climate change laws or regulations within the next few years. Implementation of treaties, legislation or regulations to reduce GHG emissions could affect Montana-Dakota's electric utility operations by requiring the expansion of energy conservation efforts and/or the increased development of renewable energy sources, as well as instituting other mandates that could significantly increase the capital expenditures and operating costs at its fossil fuel-fired generating facilities. The most prominent federal legislative proposals are based on “cap and trade” programs which place a limit on GHG emissions from major emission sources such as the electric generating industry. The impact of a cap and trade program on Montana-Dakota would be determined by considerations such as the overall GHG emissions cap level, the scope and timeframe by which the cap level is decreased, the extent to which GHG offsets are allowed, whether allowances are given to new and existing emission sources, and the indirect impact on natural gas, coal and other fuel prices. Montana-Dakota’s ability to recover costs incurred to comply with new regulations and programs will also be important in determining the financial impact on the Company.

Due to the uncertainty of technologies available to control GHG emissions and the unknown nature of compliance obligations with potential GHG emission legislation or regulations, the Company cannot determine the financial impact on its operations. If Montana-Dakota does not receive timely and full recovery of the costs of complying with GHG emission legislation and regulations from its customers, then such requirements could have an adverse impact on the results of its operations.

One of the Company's subsidiaries is subject to ongoing litigation and administrative proceedings in connection with its CBNG development activities. These proceedings have caused delays in CBNG drilling activity, and the ultimate outcome of the actions could have a material negative effect on existing CBNG operations and/or the future development of its CBNG properties.

Fidelity’s operations are and have been the subject of numerous lawsuits filed in connection with its CBNG development in the Montana and Wyoming Powder River Basin. If the plaintiffs are successful in the current lawsuits, the ultimate outcome of the actions could have a material negative effect on Fidelity's existing CBNG operations and/or the future development of its CBNG properties.

The BER in March 2006 issued a decision in a rulemaking proceeding, initiated by the NPRC, that amends the non-degradation policy applicable to water discharged in connection with CBNG operations. The amended policy includes additional limitations on factors deemed harmful, thereby restricting water discharges even further than under previous standards. Due in part to this amended policy, in May 2006, the Northern Cheyenne Tribe commenced litigation in Montana state court challenging two five-year water discharge permits that the Montana DEQ granted to Fidelity in February 2006 and which are critical to Fidelity's ability to manage water produced under present and future CBNG operations. Although the Montana state court decided the case in favor of Fidelity and the Montana DEQ in January 2009, the case was appealed to the Montana Supreme Court in March 2009. In a separate proceeding in Montana state court, plaintiffs are challenging the ROD adopted by the MBOGC in 2003 and alleging that various water management tools, including Fidelity’s water discharge permits, allow for the “wasting” of water in violation of the Montana State Constitution. If these permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

The Company is subject to extensive 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 by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return, financing, industry rate structures, 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.

Risks Relating to Foreign Operations

The value of the Company's investments in foreign operations may diminish due to political, regulatory and economic conditions and changes in currency exchange rates in countries where the Company does business.

The Company is subject to political, regulatory and economic conditions and changes in currency exchange rates in foreign countries where the Company does business. Significant changes in the political, regulatory or economic environment in these countries could negatively affect the value of the Company's investments located in these countries. Also, since the Company is unable to predict the fluctuations in the foreign currency exchange rates, these fluctuations may have an adverse impact on the Company's results of operations and cash flows.

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 directly influence the demand for electricity and natural gas, affect the price of energy commodities, affect the ability to perform services at the construction services and construction materials and contracting businesses and affect ongoing operation and maintenance and construction and drilling activities for the pipeline and energy services and natural gas and oil production businesses. In addition, severe weather can be destructive, causing outages, reduced natural gas and oil production, and/or property damage, which could require additional costs to be incurred. Physical changes to the planet could further change the intensity and frequency of severe weather conditions. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial condition 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. The 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. Pipeline and energy services competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. The natural gas and oil production business is subject to competition in the acquisition and development of natural gas and oil properties. The increase in competition could negatively affect the Company's results of operations, financial condition 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 multi-employer pension plans could have a material negative effect on the Company’s results of operations and cash flows.

The Company participates in various multi-employer pension plans for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under collective bargaining agreements. Pension expense for these plans is recognized as contributions are made. The amount of any increase or decrease in the Company’s required contributions to these multi-employer pension plans will depend upon many factors including the outcome of collective bargaining, actions taken by trustees who manage the plans, government regulations, the actual return on assets held in the plans and the potential payment of a withdrawal liability upon withdrawal from a plan, among other factors. Based on available information, the Company believes that many of the multi-employer plans to which it contributes are underfunded. The underfunded liabilities of these plans may result in increased future payments by the

Company and other participating employers. The Company's risk of such increased payments may be greater if any of the participating employers in these underfunded plans withdraws from the plan due to insolvency and is not able to contribute an amount sufficient to fund the unfunded liabilities associated with its participants in the plan. The Company may experience increased operating expenses as a result of required contributions to multi-employer pension plans, which may have a material adverse effect on the Company's results of operations and cash flows.

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, and/or available supplies 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 Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings of the Company, see Item 8 – Note 19.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2009.

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 2009 and 2008 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Per Share
2009			
First quarter	$ 22.89	$ 12.79	$ .1550
Second quarter	19.76	15.70	.1550
Third quarter	21.16	17.44	.1550
Fourth quarter	24.22	19.96	.1575
			$ .6225
2008			
First quarter	$ 27.83	$ 23.08	$ .1450
Second quarter	35.25	24.70	.1450
Third quarter	35.34	26.03	.1550
Fourth quarter	29.50	15.50	.1550
			$ .6000

As of December 31, 2009, the Company's common stock was held by approximately 15,500 stockholders of record.

Item 6. Selected Financial Data

	2009 *	2008 **	2007	2006	2005	2004
Selected Financial Data						
Operating revenues (000's):						
Electric	$196,171	$208,326	$193,367	$187,301	$181,238	$178,803
Natural gas distribution	1,072,776	1,036,109	532,997	351,988	384,199	316,120
Construction services	819,064	1,257,319	1,103,215	987,582	687,125	426,821
Pipeline and energy services	307,827	532,153	447,063	443,720	477,311	354,164
Natural gas and oil production	439,655	712,279	514,854	483,952	439,367	342,840
Construction materials and contracting	1,515,122	1,640,683	1,761,473	1,877,021	1,604,610	1,322,161
Other	9,487	10,501	10,061	8,117	6,038	4,423
Intersegment eliminations	(183,601)	(394,092)	(315,134)	(335,142)	(375,965)	(272,199)
	$4,176,501	$5,003,278	$4,247,896	$4,004,539	$3,403,923	$2,673,133
Operating income (loss) (000's):						
Electric	$36,709	$35,415	$31,652	$27,716	$29,038	$26,776
Natural gas distribution	76,899	76,887	32,903	8,744	7,404	1,820
Construction services	44,255	81,485	75,511	50,651	28,171	(5,757)
Pipeline and energy services	69,388	49,560	58,026	57,133	43,507	29,570
Natural gas and oil production	(473,399)	202,954	227,728	231,802	230,383	178,897
Construction materials and contracting	93,270	62,849	138,635	156,104	105,318	86,030
Other	(219)	2,887	(7,335)	(9,075)	(5,298)	(3,954)
	$(153,097)	$512,037	$557,120	$523,075	$438,523	$313,382
Earnings (loss) on common stock (000's):						
Electric	$24,099	$18,755	$17,700	$14,401	$13,940	$12,790
Natural gas distribution	30,796	34,774	14,044	5,680	3,515	2,182
Construction services	25,589	49,782	43,843	27,851	14,558	(5,650)
Pipeline and energy services	37,845	26,367	31,408	32,126	22,867	13,806
Natural gas and oil production	(296,730)	122,326	142,485	145,657	141,625	110,779
Construction materials and contracting	47,085	30,172	77,001	85,702	55,040	50,707
Other	7,357	10,812	(4,380)	(4,324)	13,061	15,967
Earnings (loss) on common stock before income from discontinued operations	(123,959)	292,988	322,101	307,093	264,606	200,581

Income from discontinued operations, net of tax	—	—	109,334	7,979	9,792	5,801
	$(123,959)	$292,988	$431,435	$315,072	$274,398	$206,382
Earnings (loss) per common share before discontinued operations - diluted	$(.67)	$1.59	$1.76	$1.69	$1.47	$1.14
Discontinued operations, net of tax	—	—	.60	.05	.06	.03
	$(.67)	$1.59	$2.36	$1.74	$1.53	$1.17
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	185,175	183,807	182,902	181,392	179,490	176,117
Dividends per common share	$.6225	$.6000	$.5600	$.5234	$.4934	$.4667
Book value per common share	$13.61	$14.95	$13.80	$11.88	$10.43	$9.39
Market price per common share (year end)	$23.60	$21.58	$27.61	$25.64	$21.83	$17.79
Market price ratios:						
Dividend payout	N/A	38%	24%	30%	32%	40%
Yield	2.7%	2.9%	2.1%	2.1%	2.3%	2.7%
Price/earnings ratio	N/A	13.6x	11.7x	14.7x	14.3x	15.2x
Market value as a percent of book value	173.4%	144.3%	200.1%	215.8%	209.2%	189.4%
Profitability Indicators						
Return on average common equity	(4.9)%	11.0%	18.5%	15.6%	15.7%	13.2%
Return on average invested capital	(1.7)%	8.0%	13.1%	10.6%	10.8%	9.4%
Fixed charges coverage, including preferred dividends	—***	5.3x	6.4x	6.4x	6.6x	4.8x
General						
Total assets (000's)	$5,990,952	$6,587,845	$5,592,434	$4,903,474	$4,423,562	$3,733,521
Total debt (000's)	$1,509,606	$1,752,402	$1,310,163	$1,254,582	$1,206,510	$945,487
Capitalization ratios:						
Common equity	63%	61%	66%	63%	61%	63%
Preferred stocks	—	—	—	—	—	1
Total debt	37	39	34	37	39	36
	100%	100%	100%	100%	100%	100%

* Reflects a $384.4 million after-tax noncash write-down of natural gas and oil properties.
**Reflects an $84.2 million after-tax noncash write-down of natural gas and oil properties.
*** For more information on fixed charges coverage, including preferred dividends, see Item 7 – MD&A.

Notes:

- Common stock share amounts reflect the Company's three-for-two common stock split effected in July 2006.
- Cascade and Intermountain, natural gas distribution businesses, were acquired on July 2, 2007, and October 1, 2008, respectively. For further information, see Item 8 – Note 2.

	2009	2008	2007	2006	2005	2004
Electric						
Retail sales (thousand kWh)	2,663,560	2,663,452	2,601,649	2,483,248	2,413,704	2,303,460
Sales for resale (thousand kWh)	90,789	223,778	165,639	483,944	615,220	821,516
Electric system summer generating and firm purchase capability - kW (Interconnected system)	594,700	597,250	571,160	547,485	546,085	544,220
Demand peak – kW (Interconnected system)	525,643	525,643	525,643	485,456	470,470	470,470
Electricity produced (thousand kWh)	2,203,665	2,538,439	2,253,851	2,218,059	2,327,228	2,552,873
Electricity purchased (thousand kWh)	682,152	516,654	576,613	833,647	892,113	794,829
Average cost of fuel and purchased power per kWh	$.023	$.025	$.025	$.022	$.020	$.019
Natural Gas Distribution*						
Sales (Mdk)	102,670	87,924	52,977	34,553	36,231	36,607
Transportation (Mdk)	132,689	103,504	54,698	14,058	14,565	13,856
Degree days (% of normal)						
Montana-Dakota	104 %	103 %	93 %	87 %	91 %	91 %
Cascade	105 %	108 %	102 %	—	—	—
Intermountain	107 %	90 %	—	—	—	—
Pipeline and Energy Services						
Transportation (Mdk)	163,283	138,003	140,762	130,889	104,909	114,206
Gathering (Mdk)	92,598	102,064	92,414	87,135	82,111	80,527
Natural Gas and Oil Production						
Production:						
Natural gas (MMcf)	56,632	65,457	62,798	62,062	59,378	59,750
Oil (MBbls)	3,111	2,808	2,365	2,041	1,707	1,747
Total production (MMcfe)	75,299	82,303	76,988	74,307	69,622	70,234
Average realized prices (including hedges):						
Natural gas (per Mcf)	$5.16	$7.38	$5.96	$6.03	$6.11	$4.69
Oil (per barrel)	$47.38	$81.68	$59.26	$50.64	$42.59	$34.16
Average realized prices (excluding hedges):						
Natural gas (per Mcf)	$2.99	$7.29	$5.37	$5.62	$6.87	$4.90
Oil (per barrel)	$49.76	$82.28	$59.53	$51.73	$48.73	$37.75
Proved reserves:						
Natural gas (MMcf)	448,425	604,282	523,737	538,100	489,100	453,200
Oil (MBbls)	34,216	34,348	30,612	27,100	21,200	17,100

Total reserves (MMcfe)	653,724	810,371	707,409	700,700	616,400	555,900
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	23,995	31,107	36,912	45,600	47,204	43,444
Asphalt (tons)	6,360	5,846	7,062	8,273	9,142	8,643
Ready-mixed concrete (cubic yards)	3,042	3,729	4,085	4,588	4,448	4,292
Aggregate reserves (000's tons)	1,125,491	1,145,161	1,215,253	1,248,099	1,273,696	1,257,498

* Cascade and Intermountain were acquired on July 2, 2007, and October 1, 2008, respectively. For further information, see Item 8 – Note 2.

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 and the issuance from time to time of debt and equity securities. Due to recent economic volatility, the Company in 2009 increased its focus on the use of operating cash flows to substantially fund capital expenditures. In the event that access to the commercial paper markets were to become unavailable, the Company may need to borrow under its credit agreements. 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 competitively priced energy to customers while working with them to ensure efficient usage. Both the electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations, including electric generation and transmission build-out, 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 regulations at the federal level. The ability of these segments to grow through acquisitions is subject to significant competition from other energy providers. 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 electric generating facilities and transmission lines may be subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which may necessitate increases in electric energy prices. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could increase the price and decrease the retail demand for electricity and natural gas.

Construction Services
Strategy Provide a competitive return on investment while operating in a competitive industry by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; focusing business development efforts on project areas that will permit higher margins; and properly managing risk. This segment continuously seeks opportunities to expand through strategic acquisitions.

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.

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, and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new sources of natural gas for storage, gathering and transportation services; expansion of existing gathering, transmission and storage facilities; expansion of related energy services; and incremental expansion of pipeline capacity to allow customers access to more liquid and higher-priced markets.

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

Natural Gas and Oil 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 in new areas to further expand the segment's asset base. By optimizing existing operations and taking advantage of new and incremental growth opportunities, this segment's goal is to increase both production and reserves over the long term so as to generate competitive returns on investment.

Challenges Volatility in natural gas and oil prices; ongoing environmental litigation and administrative proceedings; timely receipt of necessary permits and approvals; recruitment and retention of a skilled workforce; availability of drilling rigs, materials, auxiliary equipment and industry-related field services, and inflationary pressure on development and operating costs, all primarily in a higher price environment; and competition from other natural gas and oil 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; and continue growth through organic and acquisition opportunities. Ongoing efforts to increase margin are being pursued through the implementation of a variety of continuous improvement programs, including corporate purchasing of equipment, parts and commodities (liquid asphalt, diesel fuel, cement and other materials), and negotiation of contract price escalation provisions. 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 adequate quantities of permitted aggregate reserves being significant. A key element of the Company’s long-term strategy for this business is to further expand its presence, through acquisition, in the higher-margin materials business (rock, sand, gravel, liquid asphalt, ready-mixed concrete and related products), complementing and expanding on the Company’s expertise.

Challenges The economic downturn has adversely impacted operations, particularly in the private market. This business unit expects to continue cost containment efforts and a greater emphasis on industrial, energy and public works projects. Significant volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel continue to be a concern. Increased competition in certain construction markets has also lowered margins.

For further 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 further 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,	2009	2008	2007
	(Dollars in millions, where applicable)		
Electric	$24.1	$18.7	$17.7
Natural gas distribution	30.8	34.8	14.0
Construction services	25.6	49.8	43.8
Pipeline and energy services	37.8	26.4	31.4
Natural gas and oil production	(296.7)	122.3	142.5
Construction materials and contracting	47.1	30.2	77.0
Other	7.3	10.8	(4.3)
Earnings (loss) before discontinued operations	(124.0)	293.0	322.1
Income from discontinued operations, net of tax	—	—	109.3
Earnings (loss) on common stock	$(124.0)	$293.0	$431.4
Earnings (loss) per common share – basic:			
Earnings (loss) before discontinued operations	$(.67)	$1.60	$1.77
Discontinued operations, net of tax	—	—	.60
Earnings (loss) per common share – basic	$(.67)	$1.60	$2.37
Earnings (loss) per common share – diluted:			
Earnings (loss) before discontinued operations	$(.67)	$1.59	$1.76
Discontinued operations, net of tax	—	—	.60
Earnings (loss) per common share – diluted	$(.67)	$1.59	$2.36
Return on average common equity	(4.9)%	11.0%	18.5%

2009 compared to 2008 Consolidated loss for 2009 was $124.0 million compared to earnings of $293.0 million in 2008. This decrease was due to:

- A noncash write-down of natural gas and oil properties of $384.4 million (after tax) as well as lower average realized natural gas and oil prices of 30 percent and 42 percent, respectively and decreased natural gas production of 13 percent, partially offset by the absence of the 2008 noncash write-down of natural gas and oil properties of $84.2 million (after tax), lower depreciation, depletion and amortization expense and lower production taxes at the natural gas and oil production business
- Lower construction workloads, partially offset by lower general and administrative expense at the construction services business

Partially offsetting these decreases were:

- Increased earnings from liquid asphalt oil and asphalt operations, as well as lower selling, general and administrative expense at the construction materials and contracting business
  - Increased volumes transported to storage, higher storage services revenue and lower operation and maintenance expense at the pipeline and energy services business

2008 compared to 2007 Consolidated earnings for 2008 decreased $138.4 million from the prior year due to:

- The absence in 2008 of income from discontinued operations, net of tax, largely related to the gain on the sale of the Company's domestic independent power production assets and earnings related to an electric generating facility construction project
- An $84.2 million after-tax noncash write-down of natural gas and oil properties as well as higher depreciation, depletion and amortization expense, production taxes and lease operating costs at the natural gas and oil production business
- Decreased earnings at the construction materials and contracting business, primarily construction workloads and margins, as well as product volumes from existing operations, that were significantly lower as a result of the economic downturn

Partially offsetting these decreases were higher average natural gas and oil prices as well as increased oil and natural gas production at the natural gas and oil production business; increased earnings at the natural gas distribution business, largely due to the July 2007 acquisition of Cascade and the October 2008 acquisition of Intermountain; and higher construction workloads at the construction 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,	2009	2008	2007
	(Dollars in millions, where applicable)		
Operating revenues	$196.2	$208.3	$193.4
Operating expenses:			
Fuel and purchased power	65.7	75.4	69.6
Operation and maintenance	60.7	64.8	61.7
Depreciation, depletion and amortization	24.7	24.0	22.5
Taxes, other than income	8.4	8.7	7.9
	159.5	172.9	161.7
Operating income	36.7	35.4	31.7
Earnings	$24.1	$18.7	$17.7
Retail sales (million kWh)	2,663.5	2,663.4	2,601.7
Sales for resale (million kWh)	90.8	223.8	165.6
Average cost of fuel and purchased power per kWh	$.023	$.025	$.025

2009 compared to 2008 Electric earnings increased $5.4 million (28 percent) compared to the prior year due to:

- Higher other income, primarily allowance for funds used during construction of $5.0 million (after tax)
- Lower operation and maintenance expense of $2.3 million (after tax), largely payroll and benefit-related costs

Partially offsetting these increases were decreased sales for resale margins due to lower average rates of 31 percent and decreased volumes of 59 percent due to lower market demand and decreased plant generation.

2008 compared to 2007 Electric earnings increased $1.0 million (6 percent) compared to the prior year due to:

- Higher retail sales margins, largely due to the implementation of higher rates in Montana, and increased retail sales volumes of 2 percent
- Increased sales for resale volumes of 35 percent, primarily due to the addition of the wind-powered electric generating station near Baker, Montana, and higher plant availability

Partially offsetting these increases were:

- Higher operation and maintenance expense of $1.7 million (after tax), primarily higher payroll and benefit-related costs, as well as higher scheduled maintenance outage costs at electric generating facilities
- Increased interest expense of $1.2 million (after tax)
- Higher depreciation, depletion and amortization expense of $900,000 (after tax), largely due to higher property, plant and equipment balances

Natural Gas Distribution

Years ended December 31,	2009		2008		2007	
	(Dollars in millions, where applicable)					
Operating revenues	$1,072.8		$1,036.1		$533.0	
Operating expenses:						
Purchased natural gas sold	757.6		757.6		372.2	
Operation and maintenance	140.5		123.6		88.5	
Depreciation, depletion and amortization	42.7		32.6		19.0	
Taxes, other than income	55.1		45.4		20.4	
	995.9		959.2		500.1	
Operating income	76.9		76.9		32.9	
Earnings	$30.8		$34.8		$14.0	
Volumes (MMdk):						
Sales	102.7		87.9		53.0	
Transportation	132.7		103.5		54.7	
Total throughput	235.4		191.4		107.7	
Degree days (% of normal)*						
Montana-Dakota	104.4	%	102.7	%	92.9	%
Cascade	105.1	%	108.0	%	101.7	%
Intermountain	107.3	%	90.3	%	—	
Average cost of natural gas,						
including transportation, per dk**	$7.38		$8.14		$6.53	

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

** Regulated natural gas sales only.

Note: Cascade and Intermountain were acquired on July 2, 2007, and October 1, 2008, respectively. For further information, see Item 8 – Note 2.

2009 compared to 2008 The natural gas distribution business experienced a decrease in earnings of $4.0 million (11 percent) compared to the prior year due to:

- Absence of a $4.4 million (after tax) gain on the sale of Cascade’s natural gas management service in June 2008
- Lower earnings from energy-related services of $2.0 million (after tax)

Partially offsetting these decreases was lower operation and maintenance expense at existing operations of $2.2 million (after tax), including lower payroll and benefit-related costs.

2008 compared to 2007 The natural gas distribution business experienced an increase in earnings of $20.8 million (148 percent) compared to the prior year due to:

- Earnings of $18.4 million at Cascade and Intermountain, including a $4.4 million (after tax) gain on the sale of Cascade's natural gas management service, which were acquired on July 2, 2007, and October 1, 2008, respectively
- Increased retail sales volumes from existing operations resulting from colder weather than last year

Construction Services

Years ended December 31,	2009	2008	2007
		(In millions)	
Operating revenues	$819.0	$1,257.3	$1,103.2
Operating expenses:			
Operation and maintenance	736.3	1,122.7	979.7
Depreciation, depletion and amortization	12.8	13.4	14.3
Taxes, other than income	25.7	39.7	33.7
	774.8	1,175.8	1,027.7
Operating income	44.2	81.5	75.5
Earnings	$25.6	$49.8	$43.8

2009 compared to 2008 Construction services earnings decreased $24.2 million (49 percent) compared to the prior year, primarily due to lower construction workloads, largely in the Southwest region, partially offset by lower general and administrative expense of $6.7 million (after tax), largely payroll-related.

2008 compared to 2007 Construction services earnings increased $6.0 million (14 percent) compared to the prior year, primarily due to higher construction workloads, largely in the Southwest region. Partially offsetting this increase were lower construction margins in certain regions.

Pipeline and Energy Services

Years ended December 31,	2009	2008	2007
	(Dollars in millions)		
Operating revenues	$307.8	$532.2	$447.1
Operating expenses:			
Purchased natural gas sold	138.8	373.9	291.7
Operation and maintenance	63.1	73.8	65.6
Depreciation, depletion and amortization	25.5	23.6	21.7
Taxes, other than income	11.0	11.3	10.1
	238.4	482.6	389.1
Operating income	69.4	49.6	58.0
Income from continuing operations	37.8	26.4	31.4
Income from discontinued operations, net of tax	—	—	.1
Earnings	$37.8	$26.4	$31.5
Transportation volumes (MMdk):			
Montana-Dakota	38.9	32.0	29.3
Other	124.4	106.0	111.5
	163.3	138.0	140.8
Gathering volumes (MMdk)	92.6	102.1	92.4

2009 compared to 2008 Pipeline and energy services earnings increased $11.4 million (44 percent) largely due to:

- Increased transportation volumes of $4.9 million (after tax), largely volumes transported to storage
- Lower operation and maintenance expense of $4.5 million (after tax), largely associated with the natural gas storage litigation, which was settled in July 2009
- Higher storage services revenues of $3.1 million (after tax)
- Higher gathering rates of $2.2 million (after tax)

Partially offsetting the earnings improvement were decreased gathering volumes of 9 percent. Results also reflect lower operating revenues and lower purchased natural gas sold, both related to lower natural gas prices. The above table also reflects lower operation and maintenance expense and revenues related to energy-related service projects.

2008 compared to 2007 Pipeline and energy services earnings decreased $5.1 million (16 percent) largely due to:

- Lower storage services revenue of $3.1 million (after tax), largely related to lower storage balances and decreased volumes transported to storage of 31 percent
- Higher operation and maintenance expense, largely related to natural gas storage litigation, as previously discussed, as well as higher materials and payroll-related costs
- Higher depreciation, depletion and amortization expense of $1.3 million (after tax), largely due to higher property, plant and equipment balances

Partially offsetting these decreases were a 10 percent increase in off-system transportation volumes and demand fees, related to an expansion of the Grasslands system, and $3.0 million (after tax) of higher gathering volumes and rates.

Natural Gas and Oil Production

Years ended December 31,	2009	2008	2007
	(Dollars in millions, where applicable)		
Operating revenues:			
Natural gas	$292.3	$482.8	$374.1
Oil	147.4	229.3	140.1
Other	—	.2	.6
	439.7	712.3	514.8
Operating expenses:			
Purchased natural gas sold	—	.1	.3
Operation and maintenance:			
Lease operating costs	70.1	82.0	66.9
Gathering and transportation	24.0	24.8	20.4
Other	39.2	41.0	34.6
Depreciation, depletion and amortization	129.9	170.2	127.4
Taxes, other than income:			
Production and property taxes	29.1	54.7	36.7
Other	.8	.8	.8
Write-down of natural gas and oil properties	620.0	135.8	—
	913.1	509.4	287.1
Operating income (loss)	(473.4)	202.9	227.7
Earnings (loss)	$(296.7)	$122.3	$142.5
Production:			
Natural gas (MMcf)	56,632	65,457	62,798
Oil (MBbls)	3,111	2,808	2,365
Total Production (MMcfe)	75,299	82,303	76,988
Average realized prices (including hedges):			
Natural gas (per Mcf)	$5.16	$7.38	$5.96
Oil (per Bbl)	$47.38	$81.68	$59.26
Average realized prices (excluding hedges):			
Natural gas (per Mcf)	$2.99	$7.29	$5.37
Oil (per Bbl)	$49.76	$82.28	$59.53
Average depreciation, depletion and amortization rate, per equivalent Mcf	$1.64	$2.00	$1.59
Production costs, including taxes, per equivalent Mcf:			
Lease operating costs	$.93	$1.00	$.87
Gathering and transportation	.32	.30	.26
Production and property taxes	.39	.66	.48
	$1.64	$1.96	$1.61

2009 compared to 2008 The natural gas and oil production business experienced a loss of $296.7 million in 2009 compared to earnings of $122.3 million in 2008 due to:

- A noncash write-down of natural gas and oil properties of $384.4 million (after tax) in 2009, partially offset by the absence of the 2008 noncash write-down of natural gas and oil properties of $84.2 million (after tax), both discussed in Item 8 – Note 1
- Lower average realized natural gas and oil prices of 30 percent and 42 percent, respectively
- Decreased natural gas production of 13 percent, largely related to normal production declines at certain properties

Partially offsetting these decreases were:

- Lower depreciation, depletion and amortization expense of $25.0 million (after tax), due to lower depletion rates and decreased combined production. The lower depletion rates are largely the result of the write-downs of natural gas and oil properties in December 2008 and March 2009.
- Lower production taxes of $15.8 million (after tax) associated largely with lower average prices
- Increased oil production of 11 percent, largely related to drilling activity in the Bakken area, partially offset by normal production declines at certain properties
- Decreased lease operating expenses of $7.3 million (after tax)

2008 compared to 2007 The natural gas and oil production business experienced a decrease in earnings of $20.2 million (14 percent) due to:

- A noncash write-down of natural gas and oil properties of $84.2 million (after tax), as previously discussed
- Higher depreciation, depletion and amortization expense of $26.6 million (after tax), due to higher depletion rates and increased production
- Higher production taxes of $11.1 million (after tax), primarily due to higher average prices and increased production
- Increased lease operating costs of $9.3 million (after tax), including the East Texas properties acquired in early 2008

Partially offsetting these decreases were:

- Higher average realized natural gas prices of 24 percent
- Higher average realized oil prices of 38 percent
- Increased oil production of 19 percent, largely related to drilling activity in the Bakken area and Paradox Basin as well as production from the East Texas properties
- Increased natural gas production of 4 percent, primarily related to the acquisition of the East Texas properties, as previously discussed

Construction Materials and Contracting

Years ended December 31,	2009	2008	2007
	(Dollars in millions)		
Operating revenues	$1,515.1	$1,640.7	$1,761.5
Operating expenses:			
Operation and maintenance	1,292.0	1,437.9	1,483.5
Depreciation, depletion and amortization	93.6	100.9	95.8
Taxes, other than income	36.2	39.1	43.6
	1,421.8	1,577.9	1,622.9
Operating income	93.3	62.8	138.6
Earnings	$47.1	$30.2	$77.0
Sales (000's):			
Aggregates (tons)	23,995	31,107	36,912
Asphalt (tons)	6,360	5,846	7,062
Ready-mixed concrete (cubic yards)	3,042	3,729	4,085

2009 compared to 2008 Earnings at the construction materials and contracting business increased $16.9 million (56 percent) due to:

- Higher earnings of $17.2 million (after tax) resulting from higher liquid asphalt oil and asphalt volumes and margins
- Lower selling, general and administrative expense of $14.6 million (after tax), largely the result of cost reduction measures
- Higher aggregate margins of $8.3 million (after tax)

Partially offsetting the increases were:

- Lower aggregate and ready-mixed concrete sales volumes as a result of the continuing economic downturn
- Lower gains on the sale of property, plant and equipment of $5.5 million (after tax)

2008 compared to 2007 Earnings at the construction materials and contracting business decreased $46.8 million (61 percent) due to decreased construction workloads, margins and product volumes that were significantly lower as a result of the economic downturn, primarily as it relates to the residential market, as well as higher diesel fuel costs at existing operations, which had a combined negative effect on earnings of $53.0 million (after tax). Partially offsetting this decrease were earnings from companies acquired since the comparable prior period, which contributed approximately 8 percent of earnings for 2008.

Other and Intersegment Transactions

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

Years ended December 31,	2009	2008	2007
		(In millions)	
Other:			
Operating revenues	$9.5	$10.5	$10.0
Operation and maintenance	8.1	5.9	15.9
Depreciation, depletion and amortization	1.3	1.3	1.2
Taxes, other than income	.3	.4	.2
Intersegment transactions:			
Operating revenues	$183.6	$394.1	$315.1
Purchased natural gas sold	156.7	365.7	286.8
Operation and maintenance	26.9	28.4	28.3

For further information on intersegment eliminations, see Item 8 – Note 15.

Prospective Information

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

MDU Resources Group, Inc.

- Earnings per common share for 2010, diluted, are projected in the range of $1.10 to $1.35.

- The Company expects the percentage of 2010 earnings per common share by quarter to be in the following approximate ranges:

  - First quarter – 15 percent to 20 percent
  - Second quarter – 20 percent to 25 percent
  - Third quarter – 30 percent to 35 percent
  - Fourth quarter – 25 percent to 30 percent

- Long-term compound annual growth goals on earnings per share from operations are in the range of 7 percent to 10 percent.

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

Electric

- The Company continues to realize efficiencies and enhanced service levels through its efforts to standardize operations, share services and consolidate back-office functions among its four utility companies.

- The Company is pursuing expansion opportunities.

– In April 2009, the Company purchased a 25 MW ownership interest in the Wygen III power generation facility which is under construction near Gillette, Wyoming. This rate-based generation will replace a portion of the purchased power for the Wyoming system. The plant is expected to be online during the second quarter of 2010. In August 2009, Montana-Dakota filed an application with the WYPSC for an electric rate increase, as discussed in Item 8 – Note 18.

– The Company is developing additional wind generation, including a 19.5 MW wind generation facility in southwest North Dakota and a 10.5 MW expansion of the Diamond Willow wind facility near Baker, Montana. Both projects are expected to be commercial midyear 2010.

– The Company is analyzing potential projects for accommodating load growth and replacing purchased power contracts with company-owned generation. The Company is reviewing the construction of natural gas-fired combustion and wind generation.

- The Company is reviewing opportunities associated with the potential development of high voltage transmission lines targeted towards delivery of renewable energy from the wind rich regions that lie within its traditional electric service territory to major metropolitan areas.

Natural gas distribution

- The Company continues to realize efficiencies and enhanced service levels through its efforts to standardize operations, share services and consolidate back-office functions among its four utility companies.

Construction services

- The Company anticipates margins in 2010 to be lower than 2009 levels.

- The Company is aggressively pursuing expansion in high voltage transmission construction, renewable resource construction and military installation services. The Company was recently awarded the engineering, procurement and construction contract to build the 214-mile Montana Alberta Tie Line between Lethbridge, Alberta and Great Falls, Montana.

- The Company continues to focus on costs and efficiencies to enhance margins. With its highly skilled technical workforce, this group is prepared to take advantage of government stimulus spending on transmission infrastructure.

- Work backlog as of December 31, 2009, was approximately $383 million, compared to $604 million at December 31, 2008. The December 31, 2009, backlog includes the new Montana Alberta Tie Line project, and excludes $182 million related to the Fontainebleau project, which is proceeding through the bankruptcy process.

Pipeline and energy services

- An incremental expansion to the Grasslands Pipeline of 75,000 Mcf per day went into service August 31, 2009. The firm capacity of the Grasslands Pipeline is at its ultimate full capacity of 213,000 Mcf per day.

- The Company continues to pursue expansion of facilities and services offered to customers. Energy development within its geographic region, which includes portions of Colorado, Wyoming, Montana and North Dakota, is expanding, most notably the Bakken Shale of North Dakota and eastern Montana. Ongoing energy development is expected to have many direct and indirect benefits to its business.

- The Company has natural gas storage fields, including the largest storage field in North America located near Baker, Montana. Total working gas storage capacity is 193 Bcf for its three storage fields. The Company is pursuing a project to increase its firm deliverability and related transportation capacity from the Baker Storage field with a targeted in-service date in 2012.

Natural gas and oil production

- The Company expects to spend approximately $375 million in capital expenditures for 2010 for further exploitation of its existing properties, exploratory drilling and acquisitions of properties. This includes approximately $150 million for new growth opportunities, including acquisitions.

- The Company is also actively pursuing other potential exploratory and reserve acquisitions, which are not included in the current forecast.

- With the reduced 2009 capital expenditures and the forecasted 2010 capital expenditures, the Company expects its 2010 combined natural gas and oil production to be approximately equal to 2009 levels. The 2010 production forecast includes 3.5 Bcfe to 4 Bcfe related to growth opportunities.

  - Earnings guidance reflects estimated natural gas prices for February through December as follows:

Index*	Price Per Mcf
Ventura	$5.00 to $5.50
NYMEX	$5.25 to $5.75
CIG	$4.75 to $5.25

* Ventura is an index pricing point related to Northern Natural Gas Co.'s system; CIG is an index pricing point related to Colorado Interstate Gas Co.'s system.

- Earnings guidance reflects estimated NYMEX crude oil prices for February through December in the range of $70 to $75 per barrel.

- For 2010, the Company has hedged 45 percent to 50 percent of both its estimated natural gas and oil production. For 2011, the Company has hedged 10 percent to 15 percent of both its estimated natural gas and oil production. For 2012, the Company has hedged 5 percent to 10 percent of its estimated natural gas production. The hedges that are in place as of January 29, 2010, are summarized in the following chart:

Commodity	Type	Index*	Period Outstanding	Forward Notional Volume (MMBtu/Bbl)	Price (Per MMBtu/Bbl)
Natural Gas	Swap	HSC	1/10 - 12/10	1,606,000	$8.08
Natural Gas	Swap	NYMEX	1/10 - 12/10	3,650,000	$6.18
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$6.40
Natural Gas	Collar	NYMEX	1/10 - 12/10	1,825,000	$5.63-$6.00
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$5.855
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$6.045
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$6.045
Natural Gas	Swap	CIG	1/10 - 12/10	3,650,000	$5.03
Natural Gas	Swap	HSC	1/10 - 10/10	608,000	$5.57
Natural Gas	Swap	NYMEX	1/10 - 10/10	2,432,000	$5.645
Natural Gas	Swap	Ventura	1/10 - 12/10	1,825,000	$5.95
Natural Gas	Swap	NYMEX	4/10 - 12/10	3,025,000	$5.54
Natural Gas	Collar	NYMEX	1/10 - 3/11	2,275,000	$5.62-$6.50
Natural Gas	Swap	HSC	1/11 - 12/11	1,350,500	$8.00
Natural Gas	Swap	NYMEX	1/11 - 12/11	4,015,000	$6.1027
Natural Gas	Swap	NYMEX	1/12 - 12/12	3,477,000	$6.27
Crude Oil	Collar	NYMEX	1/10 - 12/10	365,000	$60.00-$75.00
Crude Oil	Swap	NYMEX	1/10 - 12/10	365,000	$73.20
Crude Oil	Collar	NYMEX	1/10 - 12/10	365,000	$70.00-$86.00
Crude Oil	Swap	NYMEX	1/10 - 12/10	365,000	$83.05
Crude Oil	Collar	NYMEX	1/11 - 12/11	547,500	$80.00-$94.00
Natural Gas	Basis			3,650,000	$0.25

		NYMEX to Ventura	1/10 - 12/10		
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	912,500	$0.245
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	4,562,500	$0.25
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	1,825,000	$0.225
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	912,500	$0.23
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	2,737,500	$0.23
Natural Gas	Basis	NYMEX to Ventura	1/11 - 3/11	450,000	$0.135

* Ventura is an index pricing point related to Northern Natural Gas Co.'s system; CIG is an index pricing point related to Colorado Interstate Gas Co.'s system; HSC is the Houston Ship Channel hub in southeast Texas which connects to several pipelines.

Construction materials and contracting

- Most of the markets served by construction materials are seeing positive impacts related to the federal stimulus spending.

- The Company is well positioned to take advantage of government stimulus spending on transportation infrastructure particularly in the asphalt paving and liquid asphalt oil product lines. Federal transportation stimulus of $7.9 billion was directed to states where the Company operates. Of that amount, 21 percent was spent in 2009, the remainder to be spent over the next two years, with 82 percent already obligated to specific projects by the various states.

- The Company continues to pursue work related to energy projects, such as wind towers, transmission projects, geothermal and refineries. It is also pursuing opportunities for expansion of its existing business lines including initiatives aimed at capturing additional market share and expansion into new markets. The Company has planned green field expansions for its liquid asphalt oil business.

- The Company has a strong emphasis on operational efficiencies and cost reduction.

- Liquid asphalt margins are expected to be lower in 2010 than the record levels experienced in 2009.

- Work backlog as of December 31, 2009, was approximately $459 million, compared to $453 million at December 31, 2008. Although public project margins tend to be somewhat lower than private construction-related work, the Company anticipates significant contributions to revenue from public works volume. Ninety-four percent of its year-end backlog is related to public works projects compared to 80 percent at December 31, 2008.

- As the country's 8th largest aggregate 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.

New Accounting Standards

For information regarding new accounting standards, see Item 8 – Note 1, which is incorporated 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 natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil 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.

Impairment of long-lived assets and intangibles
The Company reviews the carrying values of its long-lived assets and intangibles, excluding natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and annually for goodwill. 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. In the case of goodwill, the first step, used to identify a potential impairment, compares the fair value of the reporting unit using discounted cash flows, with its carrying amount, including goodwill. The second step, used to measure the amount of the impairment loss if step one indicates a potential impairment, compares the implied fair value of the reporting unit goodwill with the carrying amount of goodwill.

Fair value is the amount at which the asset could be bought or sold in a current transaction between market participants. The Company uses critical estimates and assumptions when testing assets for impairment, including present value techniques based on estimates of cash flows, quoted market prices or valuations by third parties, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

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 and changes in estimates of future cash flows.

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.

Natural gas and oil properties
The Company uses the full-cost method of accounting for its natural gas and oil production activities. 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 less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges are used in determining the full-cost ceiling. Judgments and assumptions are made when estimating and valuing reserves. There is risk that sustained downward movements in natural gas and oil prices, changes in estimates of reserve quantities and changes in operating and development costs could result in future noncash write-downs of the Company's natural gas and oil 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. Other factors used in the reserve estimates are prices, 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.

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 in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of revenue. Critical estimates related to the recognition of revenue include the accumulated provision for revenues subject to refund and costs on construction contracts under the percentage-of-completion method.

Estimates for revenues subject to refund are established initially for each regulatory rate proceeding and are subject to change depending on the applicable regulatory agency's (Agency) approval of final rates. These estimates are based on the Company's analysis of its as-filed application compared to previous Agency decisions in prior rate filings by the Company and other regulated companies. The Company periodically reviews the status of its outstanding regulatory proceedings and liability assumptions and may from time to time change its liability estimates subject to known developments as the regulatory proceedings move through the regulatory review process. The accuracy of the estimates is ultimately determined when the Agency issues its final ruling on each regulatory proceeding for which revenues were subject to refund. Estimates have changed from time to time as additional information has become available as to what the ultimate outcome may be and will likely continue to change in the future as new information becomes available on each outstanding regulatory proceeding that is subject to refund.

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.

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.

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.

Purchase accounting

The Company accounts for its acquisitions under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed are recorded at their respective fair values. The excess of the purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The recorded values of assets and liabilities are based in part on third-party estimates and valuations when available. The remaining values are based on management's judgments and estimates, and, accordingly, the Company's financial position or results of operations may be affected by changes in estimates and judgments.

Acquired assets and liabilities assumed by the Company that are subject to critical estimates include property, plant and equipment and intangibles.

The fair value of owned aggregate reserves is determined using qualified internal personnel as well as geologists. 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 highwalls and other exposures of the aggregate reserves. Mine plans, production history and geologic data are also used to estimate reserve quantities. Value is assigned to the aggregate reserves based on a review of market royalty rates, expected cash flows and the number of years of aggregate reserves at owned aggregate sites.

The fair value of property, plant and equipment is based on a valuation performed either by qualified internal personnel and/or outside appraisers. Fair values assigned to plant and equipment are based on several factors, including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase.

The fair value of leasehold rights is based on estimates including royalty rates, lease terms and other discernible factors for acquired leasehold rights, and estimated cash flows.

While the allocation of the purchase price of an acquisition is subject to a considerable degree of judgment and uncertainty, the Company does not expect the estimates to vary significantly once an acquisition has been completed. The Company believes its estimates have been reasonable in the past as there have been no significant valuation adjustments subsequent to the final allocation of the purchase price to the acquired assets and liabilities. In addition, goodwill impairment testing is performed annually.

Asset retirement obligations

Entities are required to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. The Company has recorded obligations related to the plugging and abandonment of natural gas and oil 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 and transmission facilities and buildings, and certain other obligations associated with leased properties.

The liability for future asset retirement obligations bears the risk of change as many factors go into the development of the estimate of these obligations and the likelihood that over time these factors can and will change. Factors used in the estimation of future asset retirement obligations include estimates of current retirement costs, future inflation factors, life of the asset and discount rates. These factors determine both a present value of the retirement liability and the accretion to the retirement liability in subsequent years.

Long-lived assets are reviewed to determine if a legal retirement obligation exists. If a legal retirement obligation exists, a determination of the liability is made if a reasonable estimate of the present value of the obligation can be made. The present value of the retirement obligation is calculated by inflating current estimated retirement costs of the long-lived asset over its expected life to determine the expected future cost and then discounting the expected future cost back to the present value using a discount rate equal to the credit-adjusted risk-free interest rate in effect when the liability was initially recognized.

These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will change as the estimated useful lives of the assets change, the current estimated retirement costs change, new legal retirement obligations occur and/or as existing legal asset retirement obligations, for which a reasonable estimate of fair value could not initially be made because of the range of time over which the Company may settle the obligation is unknown or cannot be estimated, become less uncertain and a reasonable estimate of the future liability can be made.

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 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.

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 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

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 2009 increased $60.5 million from the comparable prior period. Lower working capital requirements of $263.6 million were partially offset by lower income before depreciation, depletion and amortization and before the after-tax noncash write-down of natural gas and oil properties, largely the effects of lower commodity prices at the natural gas and oil production business. The lower working capital requirements were largely the result of lower receivables and lower net natural gas costs recoverable through rate adjustments at the natural gas distribution business, as well as lower working capital requirements at the other business segments.

Cash flows provided by operating activities in 2008 increased $223.0 million from the comparable prior period, due to:

- Higher income from continuing operations before depreciation, depletion and amortization and before the after-tax noncash write-down of natural gas and oil properties
    - Absence of cash flows used related to discontinued operations in 2007 of $71.4 million

Investing activities Cash flows used in investing activities in 2009 decreased $675.2 million from the comparable prior period due to:

- Lower cash used in connection with acquisitions, net of cash acquired, of $527.1 million, primarily due to the absence of the 2008 acquisitions of Intermountain and natural gas and oil producing properties in East Texas
- Decreased ongoing capital expenditures of $297.8 million, primarily at the natural gas and oil production business

Partially offsetting the decrease in cash flows used in investing activities were lower proceeds from investments of $89.5 million and decreased net proceeds from the sale or disposition of property of $60.2 million, largely at the construction materials and contracting business.

Cash flows used in investing activities in 2008 increased $765.1 million from the comparable prior period due to:

- Absence of cash flows provided by discontinued operations in 2007 of $548.2 million, primarily the result of the sale of the domestic independent power production assets in the third quarter of 2007
- Increased ongoing capital expenditures of $188.2 million, largely at the natural gas and oil production business
- Higher cash used in connection with acquisitions, net of cash acquired, of $185.1 million, largely due to the acquisition of Intermountain and natural gas and oil producing properties in East Texas in 2008, partially offset by the absence of the 2007 acquisition of Cascade

Partially offsetting the increase in cash flows used in investing activities were higher proceeds from investments of $85.8 million in 2008, as well as the absence of cash used for investments of $67.1 million in 2007.

Financing activities Cash flows provided by financing activities in 2009 decreased $559.6 million from the comparable prior period, primarily due to lower issuance of long-term debt and short-term borrowings, higher repayment of long-term debt, partially offset by increased issuance of common stock. Lower cash flows provided by financing activities in 2009 reflects lower ongoing capital expenditures and acquisitions, as well as increased cash provided by operating activities.

Cash flows provided by financing activities in 2008 increased $456.2 million from the comparable prior period, primarily due to higher issuance of long-term debt of $333.7 million as well as higher net short-term borrowings of $101.7 million, largely related to higher ongoing capital expenditures and acquisitions.

Defined benefit pension plans

The Company has qualified noncontributory defined benefit pension plans (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, 2009, the Pension Plans' accumulated benefit obligations exceeded these plans' assets by approximately $85.0 million. Pretax pension expense reflected in the years ended December 31, 2009, 2008 and 2007, was $8.2 million,

$4.6 million and $6.5 million, respectively. The Company's pension expense is currently projected to be approximately $3.5 million to $4.5 million in 2010. Funding for the Pension Plans is actuarially determined. The minimum required contributions for 2009, 2008 and 2007 were approximately $7.3 million, $6.8 million and $1.8 million, respectively. For further information on the Company's Pension Plans, see Item 8 – Note 16.

Capital expenditures

The Company's capital expenditures for 2007 through 2009 and as anticipated for 2010 through 2012 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2007	2008	2009	2010	2011	2012
			(In millions)			
Capital expenditures:						
Electric	$91	$73	$115	$105	$72	$100
Natural gas distribution	500	398	44	76	60	59
Construction services	18	24	13	13	11	11
Pipeline and energy services	39	43	70	15	28	149
Natural gas and oil production	284	711	183	375 **	359	321
Construction materials and contracting	190	128	27	37	52	62
Other	2	1	3	1	1	1
Net proceeds from sale or disposition of property	(25)	(87)	(27)	(4)	(7)	(1)
Net capital expenditures before discontinued operations	1,099	1,291	428	618	576	702
Discontinued operations	(548)	—	—	—	—	—
Net capital expenditures	551	1,291	428	618	576	702
Retirement of long-term debt	232	201	293	13	72	136
	$783	$1,492	$721	$631	$648	$838

*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.

** Includes approximately $150 million for new growth opportunities, including potential acquisitions.

Capital expenditures for 2009, 2008 and 2007 in the preceding table include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions and the outstanding indebtedness related to the 2008 Intermountain acquisition and the 2007 Cascade acquisition. The net noncash transactions were immaterial in 2009, $97.6 million in 2008 and $217.3 million in 2007.

In 2009, the Company acquired a pipeline and energy services business in Montana. The total purchase consideration for this business and purchase price adjustments with respect to certain other acquisitions made prior to 2009, consisting of the Company's common stock and cash, was $22.0 million.

The 2009 capital expenditures, including those for the previously mentioned acquisitions and retirements 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 2010 through 2012 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering projects
- Further development of existing properties, exploratory drilling and acquisitions at the natural gas and oil production segment
- Power generation opportunities, including certain costs for additional electric generating capacity
- 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 2010 through 2012 will be met from various sources, including internally generated funds; the Company's credit facilities, as described below; 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 below, 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, 2009. 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 credit facilities of the Company and its subsidiaries at December 31, 2009:

Company	Facility	Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date	
(Dollars in millions)									
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$125.0		$—	(b)	$—		6/21/11	
MDU Energy Capital, LLC	Master shelf agreement	$175.0		$165.0		$—		8/14/10	(c)
Cascade Natural Gas Corporation	Revolving credit agreement	$50.0	(d)	$—		$1.9	(e)	12/28/12	(f)
Intermountain Gas Company	Revolving credit agreement	$65.0	(g)	$10.3		$—		8/31/10	
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (h)	$400.0		$—	(b)	$26.4	(e)	12/13/12	
Williston Basin Interstate Pipeline Company	Uncommitted long-term private shelf agreement	$125.0		$87.5		$—		12/23/10	(i)

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (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) Or such time as the agreement is terminated by either of the parties thereto.
(d) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(e) The outstanding letters of credit, as discussed in Item 8 – Note 19, reduce amounts available under the credit agreement.
(f) Provisions allow for an extension of up to two years upon consent of the banks.
(g) Certain provisions allow for increased borrowings, up to a maximum of $70 million.
(h) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.
(i) Certain provisions allow for an extension to December 23, 2011.

In order to maintain the Company's and Centennial's respective commercial paper programs in the amounts indicated above, both the Company and Centennial must have revolving credit agreements in place at least equal to the amount of their commercial paper programs. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the above table.

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MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. The commercial paper borrowings 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 further 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.

In November 2009, the Company completed a defeasance of its outstanding 8.60% Secured Medium-Term Notes under the Mortgage and the Mortgage was discharged. For more information, see Item 8 – Note 9.

The Company's coverage of fixed charges including preferred stock dividends was 5.3 times for the 12 months ended December 31, 2008. Due to the $384.4 million after-tax noncash write-down of natural gas and oil properties in the first quarter of 2009, earnings were insufficient by $228.7 million to cover fixed charges for the 12 months ended December 31, 2009. If the $384.4 million after-tax noncash write-down is excluded, the coverage of fixed charges including preferred stock dividends would have been 4.6 times for the 12 months ended December 31, 2009. Common stockholders' equity as a percent of total capitalization was 63 percent and 61 percent at December 31, 2009 and 2008, respectively.

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

In September 2008, the Company entered into a Sales Agency Financing Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 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, which terminates on May 28, 2011. Proceeds from the sale of shares of common stock under the agreement have been and are expected to be used for corporate development purposes and other general corporate purposes. The Company issued approximately 600,000 shares of stock during the fourth quarter under the Sales Agency Financing Agreement, resulting in net proceeds of $12.2 million, and has issued a total of approximately 3.2 million shares of stock under the Sales Agency Financing Agreement through December 31, 2009, resulting in total net proceeds of $63.1 million.

The Company currently has authorization to issue and sell up to $1.0 billion of securities pursuant to a registration statement on file with the SEC. The Company may sell all or a portion of such securities if warranted by market conditions and the Company's capital requirements. Any 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.

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. The Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial 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 further 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.

Off balance sheet arrangements

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses that Petrobras may incur from certain contingent liabilities specified in the purchase agreement. For more information, see Item 8 – Note 19.

Centennial continues to guarantee CEM's obligations under a construction contract for a 550-MW combined-cycle 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 long-term debt, operating leases, purchase commitments and uncertain tax positions, see Item 8 – Notes 9, 14 and 19. At December 31, 2009, the Company's commitments under these obligations were as follows:

	2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Long-term debt	$12.6	$72.3	$136.3	$258.8	$9.1	$1,010.2	$1,499.3
Estimated interest payments*	91.9	87.8	84.0	69.8	62.3	342.6	738.4
Operating leases	25.2	20.3	15.3	12.6	6.7	43.9	124.0
Purchase commitments	507.6	288.3	192.1	105.7	90.3	234.9	1,418.9
	$637.3	$468.7	$427.7	$446.9	$168.4	$1,631.6	$3,780.6

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

Not reflected in the table above are $6.1 million in uncertain tax positions for which the year of settlement is not reasonably possible to determine.

Effects of Inflation
Inflation did not have a significant effect on the Company's operations in 2009, 2008 or 2007.

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 – 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 natural gas and oil and basis differentials on forecasted sales of natural gas and oil production. Cascade and Intermountain utilize derivative instruments to manage a portion of their regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas.

The following table summarizes derivative agreements entered into by Fidelity, Cascade and Intermountain as of December 31, 2009. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade and Intermountain to receive variable prices and pay fixed prices.

(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas swap agreements maturing in 2010	$5.99	21,071	$5,968
Natural gas swap agreement maturing in 2011	$8.00	1,351	$2,377
Natural gas basis swap agreements maturing in 2010	$.24	14,600	$(4,021)
Natural gas basis swap agreement maturing in 2011	$.14	450	$(108)
Oil swap agreements maturing in 2010	$78.13	730	$(3,043)
Cascade			
Natural gas swap agreements maturing in 2010	$8.03	8,922	$(23,058)
Natural gas swap agreements maturing in 2011	$8.10	2,270	$(4,756)
Intermountain			
Natural gas swap agreements maturing in 2010	$6.03	900	$(86)

	Weighted Average Floor/Ceiling Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas collar agreements maturing in 2010	$5.63/$6.25	3,650	$(39)
Natural gas collar agreement maturing in 2011	$5.62/$6.50	450	$(6)
Oil collar agreements maturing in 2010	$65.00/$80.50	730	$(4,867)
Oil collar agreement maturing in 2011	$80.00/$94.00	548	$357

The following table summarizes derivative agreements entered into by Fidelity, Cascade and Intermountain as of December 31, 2008. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade and Intermountain to receive variable prices and pay fixed prices.

(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per MMBtu)	Forward Notional Volume (MMBtu)	Fair Value
Fidelity			
Natural gas swap agreements maturing in 2009	$8.73	10,920	$33,059
Natural gas swap agreements maturing in 2010	$8.08	1,606	$2,011
Natural gas swap agreements maturing in 2011	$8.00	1,351	$1,211
Natural gas basis swap agreement maturing in 2009	$.61	3,650	$(1,349)
Cascade			
Natural gas swap agreements maturing in 2009	$8.26	19,350	$(49,883)
Natural gas swap agreements maturing in 2010	$8.03	8,922	$(18,947)
Natural gas swap agreements maturing in 2011	$8.10	2,270	$(4,587)
Intermountain			
Natural gas swap agreements maturing in 2009	$5.54	7,905	$(5,297)

	Weighted Average Floor/Ceiling Price (Per MMBtu)	Forward Notional Volume (MMBtu)	Fair Value
Fidelity			
Natural gas collar agreements maturing in 2009	$8.52/$9.56	14,965	$45,105

Note: The fair value of Cascade’s natural gas swap agreements is presented net of the collateral provided to the counterparty of $11.1 million.

Interest rate risk

The Company uses fixed rate long-term debt and from time to time 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 or permanent financing. The Company also has historically used interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk. At December 31, 2009 and 2008, the Company had no outstanding interest rate hedges.

The following table shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2009.

	2010	2011	2012	2013	2014	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$12.6	$72.3	$136.3	$258.8	$9.1	$ 1,010.2	$1,499.3	$1,566.3
Weighted average interest rate	6.9 %	7.1 %	5.9 %	6.0 %	6.9 %	6.1 %	6.1 %	—

Foreign currency risk

MDU Brasil's equity method investments in the Brazilian Transmission Lines are exposed to market risks from changes in foreign currency exchange rates between the U.S. dollar and the Brazilian Real. For further information, see Item 8 – Note 4. At December 31, 2009 and 2008, 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) 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 financial statements for external purposes in accordance with generally accepted accounting principles.

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, 2009. 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.

Based on our evaluation under the framework in Internal Control–Integrated Framework, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

/s/ Terry D. Hildestad	/s/ Doran N. Schwartz
Terry D. Hildestad	Doran N. Schwartz
President and Chief Executive Officer	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, 2009 and 2008, and the related consolidated statements of income, common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedule for each of the three years in the period ended December 31, 2009, listed in the Index at Item 15. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedule, 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.

As discussed in Note 1 to the consolidated financial statements, the Company adopted the definitions and required pricing assumptions outlined in the Modernization of Oil and Gas Reporting rules issued by the Securities and Exchange Commission effective as of December 31, 2009.

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, 2009, based on the criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 17, 2010, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 17, 2010

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, 2009, based on criteria established in Internal Control–Integrated Framework 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, 2009, based on the criteria established in Internal Control–Integrated Framework 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 schedule as of and for the year ended December 31, 2009 of the Company and our report February 17, 2010 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of the definitions and required pricing assumptions outlined in the Modernization of Oil and Gas Reporting rules issued by the Securities and Exchange Commission effective as of December 31, 2009.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 17, 2010

MDU RESOURCES GROUP, INC.
Consolidated Statements of Income

Years ended December 31,	2009	2008	2007
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	$1,504,269	$1,685,199	$1,095,709
Construction services, natural gas and oil production, construction materials and contracting, and other	2,672,232	3,318,079	3,152,187
Total operating revenues	4,176,501	5,003,278	4,247,896
Operating expenses:			
Fuel and purchased power	65,717	75,333	69,616
Purchased natural gas sold	739,678	765,900	377,404
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	263,869	262,053	215,587
Construction services, natural gas and oil production, construction materials and contracting, and other	2,143,195	2,686,055	2,572,864
Depreciation, depletion and amortization	330,542	366,020	301,932
Taxes, other than income	166,597	200,080	153,373
Write-down of natural gas and oil properties (Note 1)	620,000	135,800	—
Total operating expenses	4,329,598	4,491,241	3,690,776
Operating income (loss)	(153,097)	512,037	557,120
Earnings from equity method investments	8,499	6,627	19,609
Other income	9,331	4,012	8,318
Interest expense	84,099	81,527	72,237
Income (loss) before income taxes	(219,366)	441,149	512,810
Income taxes	(96,092)	147,476	190,024
Income (loss) from continuing operations	(123,274)	293,673	322,786
Income from discontinued operations, net of tax (Note 3)	—	—	109,334
Net income (loss)	(123,274)	293,673	432,120
Dividends on preferred stocks	685	685	685
Earnings (loss) on common stock	$(123,959)	$292,988	$431,435
Earnings (loss) per common share – basic:			
Earnings (loss) before discontinued operations	$(.67)	$1.60	$1.77
Discontinued operations, net of tax	—	—	.60
Earnings (loss) per common share – basic	$(.67)	$1.60	$2.37
Earnings (loss) per common share – diluted:			
Earnings (loss) before discontinued operations	$(.67)	$1.59	$1.76
Discontinued operations, net of tax	—	—	.60
Earnings (loss) per common share – diluted	$(.67)	$1.59	$2.36
Dividends per common share	$.6225	$.6000	$.5600
Weighted average common shares outstanding – basic	185,175	183,100	181,946
Weighted average common shares outstanding – diluted	185,175	183,807	182,902

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

MDU RESOURCES GROUP, INC.
Consolidated Balance Sheets

December 31,	2009	2008
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$175,114	$51,714
Receivables, net	531,980	707,109
Inventories	249,804	261,524
Deferred income taxes	28,145	—
Short-term investments	2,833	2,467
Commodity derivative instruments	7,761	78,164
Prepayments and other current assets	66,021	171,314
Total current assets	1,061,658	1,272,292
Investments	145,416	114,290
Property, plant and equipment (Note 1)	6,766,582	7,062,237
Less accumulated depreciation, depletion and amortization	2,872,465	2,761,319
Net property, plant and equipment	3,894,117	4,300,918
Deferred charges and other assets:		
Goodwill (Note 5)	629,463	615,735
Other intangible assets, net (Note 5)	28,977	28,392
Other	231,321	256,218
Total deferred charges and other assets	889,761	900,345
Total assets	$5,990,952	$6,587,845
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings (Note 9)	$10,300	$105,100
Long-term debt due within one year	12,629	78,666
Accounts payable	281,906	432,358
Taxes payable	55,540	49,784
Deferred income taxes	—	20,344
Dividends payable	29,749	28,640
Accrued compensation	47,425	55,646
Commodity derivative instruments	36,907	56,529
Other accrued liabilities	192,729	140,408
Total current liabilities	667,185	967,475
Long-term debt (Note 9)	1,486,677	1,568,636
Deferred credits and other liabilities:		
Deferred income taxes	590,968	727,857
Other liabilities	674,475	562,801
Total deferred credits and other liabilities	1,265,443	1,290,658
Commitments and contingencies (Notes 16, 18 and 19)		
Stockholders' equity:		
Preferred stocks (Note 11)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 12)		
Authorized – 500,000,000 shares, $1.00 par value		
Issued – 188,389,265 shares in 2009 and 184,208,283 shares in 2008	188,389	184,208

Other paid-in capital	1,015,678	938,299
Retained earnings	1,377,039	1,616,830
Accumulated other comprehensive income (loss)	(20,833)	10,365
Treasury stock at cost – 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,556,647	2,746,076
Total stockholders' equity	2,571,647	2,761,076
Total liabilities and stockholders' equity	$5,990,952	$6,587,845

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

MDU RESOURCES GROUP, INC.
Consolidated Statements of Common Stockholders' Equity
Years ended December 31, 2009, 2008 and 2007

	Common Stock		Other Paid-in	Retained	Accumulated Other Comprehensive Income (Loss)	Treasury Stock		
	Shares	Amount	Capital	Earnings		Shares	Amount	Total
	(In thousands, except shares)							
Balance at December 31, 2006	181,557,543	$181,558	$874,253	$1,104,210	$(6,482)	(538,921)	$(3,626)	$2,149,913
Comprehensive income:								
Net income	—	—	—	432,120	—	—	—	432,120
Other comprehensive income (loss), net of tax -								
Net unrealized loss on derivative instruments qualifying as hedges	—	—	—	—	(13,505)	—	—	(13,505)
Postretirement liability adjustment	—	—	—	—	3,012	—	—	3,012
Foreign currency translation adjustment	—	—	—	—	7,177	—	—	7,177
Net unrealized gain on available-for-sale investments	—	—	—	—	405	—	—	405
Total comprehensive income	—	—	—	—	—	—	—	429,209
Uncertain tax positions transition adjustment	—	—	—	31	—	—	—	31
Dividends on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends on common stock	—	—	—	(102,091)	—	—	—	(102,091)

Tax benefit on stock-based compensation	—	—	5,398	—	—	—	—	5,398
Issuance of common stock	1,388,985	1,389	33,155	—	—	—	—	34,544
Balance at December 31, 2007	182,946,528	182,947	912,806	1,433,585	(9,393)	(538,921)	(3,626)	2,516,319
Comprehensive income:								
Net income	—	—	—	293,673	—	—	—	293,673
Other comprehensive income (loss), net of tax -								
Net unrealized gain on derivative instruments qualifying as hedges	—	—	—	—	43,448	—	—	43,448
Postretirement liability adjustment	—	—	—	—	(13,751)	—	—	(13,751)
Foreign currency translation adjustment	—	—	—	—	(9,534)	—	—	(9,534)
Total comprehensive income	—	—	—	—	—	—	—	313,836
Fair value option transition adjustment	—	—	—	405	(405)	—	—	—
Dividends on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends on common stock	—	—	—	(110,148)	—	—	—	(110,148)
Tax benefit on stock-based compensation	—	—	4,441	—	—	—	—	4,441
Issuance of common stock	1,261,755	1,261	21,052	—	—	—	—	22,313
Balance at December 31, 2008	184,208,283	184,208	938,299	1,616,830	10,365	(538,921)	(3,626)	2,746,076
Comprehensive loss:								
Net loss	—	—	—	(123,274)	—	—	—	(123,274)
Other comprehensive								

income (loss), net of tax - Net unrealized loss on derivative instruments qualifying as hedges	—	—	—	—	(51,684)	—	—	(51,684)
Postretirement liability adjustment	—	—	—	—	9,918	—	—	9,918
Foreign currency translation adjustment	—	—	—	—	10,568	—	—	10,568
Total comprehensive loss	—	—	—	—	—	—	—	(154,472)
Dividends on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends on common stock	—	—	—	(115,832)	—	—	—	(115,832)
Tax benefit on stock-based compensation	—	—	(117)	—	—	—	—	(117)
Issuance of common stock	4,180,982	4,181	77,496	—	—	—	—	81,677
Balance at December 31, 2009	188,389,265	$188,389	$1,015,678	$1,377,039	$(20,833)	(538,921)	$(3,626)	$2,556,647

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

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MDU RESOURCES GROUP, INC.
Consolidated Statements of Cash Flows

Years ended December 31,	2009	2008	2007
		(In thousands)	
Operating activities:			
Net income (loss)	$(123,274)	$293,673	$432,120
Income from discontinued operations, net of tax	—	—	109,334
Income (loss) from continuing operations	(123,274)	293,673	322,786
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	330,542	366,020	301,932
Earnings, net of distributions, from equity method investments	(3,018)	365	(14,031)
Deferred income taxes	(169,764)	64,890	67,272
Write-down of natural gas and oil properties (Note 1)	620,000	135,800	—
Changes in current assets and liabilities, net of acquisitions:			
Receivables	132,939	27,165	(40,256)
Inventories	13,969	(18,574)	(7,130)
Other current assets	67,803	(64,771)	(7,356)
Accounts payable	(61,867)	28,205	24,702
Other current liabilities	44,039	(38,738)	(22,932)
Other noncurrent changes	(4,683)	(7,848)	9,594
Net cash provided by continuing operations	846,686	786,187	634,581
Net cash used in discontinued operations	—	—	(71,389)
Net cash provided by operating activities	846,686	786,187	563,192
Investing activities:			
Capital expenditures	(448,675)	(746,478)	(558,283)
Acquisitions, net of cash acquired	(6,410)	(533,543)	(348,490)
Net proceeds from sale or disposition of property	26,679	86,927	24,983
Investments	(3,740)	85,773	(67,140)
Proceeds from sale of equity method investments	—	—	58,450
Net cash used in continuing operations	(432,146)	(1,107,321)	(890,480)
Net cash provided by discontinued operations	—	—	548,216
Net cash used in investing activities	(432,146)	(1,107,321)	(342,264)
Financing activities:			
Issuance of short-term borrowings	10,300	216,400	311,700
Repayment of short-term borrowings	(105,100)	(113,000)	(310,000)
Issuance of long-term debt	145,000	453,929	120,250
Repayment of long-term debt	(292,907)	(200,527)	(232,464)
Proceeds from issuance of common stock	65,207	15,011	17,263
Dividends paid	(115,023)	(108,591)	(100,641)
Tax benefit on stock-based compensation	601	4,441	5,398
Net cash provided by (used in) continuing operations	(291,922)	267,663	(188,494)
Net cash provided by discontinued operations	—	—	—
Net cash provided by (used in) financing activities	(291,922)	267,663	(188,494)

Effect of exchange rate changes on cash and cash equivalents	782	(635)	308
Increase (decrease) in cash and cash equivalents	123,400	(54,106)	32,742
Cash and cash equivalents – beginning of year	51,714	105,820	73,078
Cash and cash equivalents – end of year	$175,114	$51,714	$105,820

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, construction services, pipeline and energy services, natural gas and oil production, construction materials and contracting, and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Construction services, natural gas and oil production, construction materials and contracting, and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. 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.

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.

Allowance for doubtful accounts
The Company's allowance for doubtful accounts as of December 31, 2009 and 2008, was $16.6 million and $13.7 million, respectively.

Natural gas in storage
Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories and was $35.6 million and $27.6 million at December 31, 2009 and 2008, respectively. The remainder of natural gas in storage, which largely represents the cost of the gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $59.6 million and $43.4 million at December 31, 2009 and 2008, respectively.

Inventories

Inventories, other than natural gas in storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $80.1 million and $89.1 million, materials and supplies of $58.1 million and $70.3 million, asphalt oil of $23.0 million and $22.1 million, and other inventories of $53.0 million and $52.4 million, as of December 31, 2009 and 2008, respectively. These inventories were stated at the lower of average cost or market value.

Investments

The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, investments in fixed-income and equity securities and auction rate securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. On January 1, 2008, the Company elected to measure its investments in certain fixed-income and equity securities at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. These investments had previously been accounted for as available-for-sale investments and were recorded at fair value with any unrealized gains and losses, net of income taxes, recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets until realized. The Company accounts for auction rate securities as available-for-sale. For more information, see Notes 8 and 16 and comprehensive income (loss) in this note.

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 natural gas and oil production properties as described in natural gas and oil 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, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $11.5 million, $9.0 million and $7.1 million in 2009, 2008 and 2007, respectively. 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 natural gas and oil production properties, which are amortized on the units-of-production method based on total 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:

	2009	2008	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$486,710	$408,851	58
Distribution	230,795	219,501	36
Transmission	146,373	142,081	44
Other	77,913	78,292	12
Natural gas distribution:			
Distribution	1,218,124	1,260,651	39
Other	238,084	168,836	21
Pipeline and energy services:			
Transmission	351,019	322,276	52
Gathering	41,815	41,825	19
Storage	33,701	32,592	52
Other	33,283	31,925	27
Nonregulated:			
Construction services:			
Land	4,526	4,526	—
Buildings and improvements	15,110	12,913	23
Machinery, vehicles and equipment	87,462	84,042	7
Other	9,138	9,820	5
Pipeline and energy services:			
Gathering	202,467	201,323	17
Other	12,914	10,980	10
Natural gas and oil production:			
Natural gas and oil properties	1,993,594	2,443,946	*
Other	35,200	33,456	9
Construction materials and contracting:			
Land	127,928	127,279	—
Buildings and improvements	65,778	68,356	20
Machinery, vehicles and equipment	925,747	932,545	12
Construction in progress	3,733	11,488	—
Aggregate reserves	391,803	384,361	**
Other:			
Land	2,942	2,942	—
Other	30,423	27,430	19
Less accumulated depreciation, depletion and amortization	2,872,465	2,761,319	
Net property, plant and equipment	$3,894,117	$4,300,918	

*Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $1.64, $2.00 and $1.59 for the years ended December 31, 2009, 2008 and 2007, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $178.2 million and $232.1 million were excluded from amortization at December 31, 2009 and 2008, respectively.

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

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Impairment of long-lived assets
The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil 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. No significant impairment losses were recorded in 2009, 2008 and 2007. Unforeseen events and changes in circumstances could require the recognition of other 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. For more information on goodwill, see Note 5.

Natural gas and oil properties
The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil 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 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 less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. Prior to that date, if capitalized costs exceeded the full-cost ceiling at the end of any quarter, a permanent noncash write-down was required to be charged to earnings in that quarter unless subsequent price changes eliminated or reduced an indicated write-down. Effective December 31, 2009, if capitalized costs 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.

Due to low natural gas and oil prices that existed on March 31, 2009, and December 31, 2008, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2009, and December 31, 2008. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-downs amounted to $620.0 million and $135.8 million ($384.4 million and $84.2 million after tax) for the years ended December 31, 2009 and 2008, respectively.

The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized additional write-downs of its natural gas and oil properties of $107.9 million ($66.9 million after tax) at March 31, 2009, and $79.2 million ($49.1 million after tax) at December 31, 2008, 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.

At December 31, 2009, the Company’s full-cost ceiling exceeded the Company’s capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2009, could result in a future write-down of the Company’s natural gas and oil properties.

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2009, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2009	2008	2007	2006 and prior
			(In thousands)		
Acquisition	$122,806	$4,287	$81,954	$7,972	$28,593
Development	20,377	9,997	7,149	3,231	—
Exploration	28,216	19,311	8,093	811	1
Capitalized interest	6,815	1,336	3,865	478	1,136
Total costs not subject to amortization	$178,214	$34,931	$101,061	$12,492	$29,730

Costs not subject to amortization as of December 31, 2009, consisted primarily of unevaluated leaseholds, drilling costs, seismic costs and capitalized interest associated primarily with natural gas and oil development in the Paradox Basin in Utah; Big Horn Basin in Wyoming; east Texas properties; and CBNG in the Powder River Basin of Wyoming and Montana. 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 $92.6 million and $123.2 million at December 31, 2009 and 2008, 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 natural gas and oil production properties only on that portion of production sold and allocable to the Company's ownership interest in the related well. 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 of $28.8 million and $40.1 million at December 31, 2009 and 2008, respectively, represent revenues recognized in excess of amounts billed and were

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included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $49.3 million and $106.9 million at December 31, 2009 and 2008, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to $45.4 million and $86.9 million at December 31, 2009 and 2008, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $44.0 million and $67.7 million at December 31, 2009 and 2008, respectively. The long-term retainage which was included in deferred charges and other assets – other was $1.4 million and $19.2 million at December 31, 2009 and 2008, respectively.

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 natural gas and oil production at Fidelity for a period up to 36 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 natural gas and oil 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, with the unrealized gains or losses recognized as a component of accumulated other comprehensive income (loss). 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 swap and collar agreements are reflected at fair value, based upon futures prices, volatility and time to maturity, among other things.

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.

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 $37.4 million and $64,000 at December 31, 2009 and 2008, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $982,000 and $51.7 million at December 31, 2009 and 2008, 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 the Brazilian Transmission Lines, as further 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 weighted average daily exchange rates. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

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, restricted stock grants and performance share awards. In 2008 and 2007, there were no shares excluded from the calculation of diluted earnings per share. Diluted loss per common share for 2009 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 2009, the effect of outstanding stock options, restricted stock grants and 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.

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 natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil 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 were as follows:

Years ended December 31,	2009	2008	2007
		(In thousands)	
Interest, net of amount capitalized	$81,267	$77,152	$74,404
Income taxes	$39,807	$113,212	$214,573

Income taxes paid for the year ended December 31, 2007, were higher than the amount paid for the years ended December 31, 2009 and 2008, primarily due to higher estimated quarterly tax payments paid in 2007 due in large part to the gain on the sale of the domestic independent power production assets as discussed in Note 3.

New accounting standards

Codification In June 2009, the FASB established the ASC as the source of authoritative generally accepted accounting principles recognized by the FASB. The ASC is a reorganization of GAAP into a topical format. It was effective for the Company in the third quarter of 2009. The adoption of the Codification required the Company to revise its disclosures when referencing generally accepted accounting principles.

Fair Value Measurements and Disclosures In September 2006, the FASB established guidance that defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The guidance applies under other accounting pronouncements that require or permit fair value measurements with certain exceptions and was effective for the Company on January 1, 2008. In February 2008, this guidance was revised to delay the effective date for certain nonfinancial assets and nonfinancial liabilities to January 1, 2009. The types of assets and liabilities that are recognized at fair value effective January 1, 2009, due to the delayed effective date, include nonfinancial assets and nonfinancial liabilities initially measured at fair value in a business combination or new basis event, certain fair value measurements associated with goodwill impairment testing, indefinite-lived intangible assets and nonfinancial long-lived assets measured at fair value for impairment assessment, and asset retirement obligations initially measured at fair value. The adoption of the fair value measurements and disclosure guidance, including the application to certain nonfinancial assets and nonfinancial liabilities with a delayed effective date of January 1, 2009, did not have a material effect on the Company's financial position or results of operations.

Business Combinations In December 2007, the FASB issued guidance related to business combinations that requires an acquirer to recognize and measure the assets acquired, liabilities assumed and any noncontrolling interests in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exception. The business combination guidance also requires that acquisition-related costs will be generally expensed as incurred, and expands the disclosure requirements for business combinations. In addition, the business combination guidance was amended and clarified to address application issues raised in regard to initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This guidance and its amendments were effective for the Company on January 1, 2009. The adoption of the business combination guidance and its amendments did not have a material effect on the Company’s financial position or results of operations.

Noncontrolling Interests In December 2007, the FASB established accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This guidance was effective for the Company on January 1, 2009. The adoption of the noncontrolling interest guidance did not have a material effect on the Company’s financial position or results of operations.

Derivative Instruments and Hedging Activities In March 2008, the FASB released guidance related to derivative instruments and hedging activities that requires enhanced disclosures about an entity’s derivative and hedging activities including how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for, and how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. This guidance was effective for the Company on January 1, 2009. The adoption of the derivative instruments and hedging activities guidance requires additional disclosures regarding the Company’s derivative instruments; however, it did not impact the Company’s financial position or results of operations.

Pensions and Other Postretirement Benefits In December 2008, the FASB issued guidance on an employer’s disclosures about plan assets of a defined benefit pension or other postretirement plan to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period and significant concentrations of risk within plan assets. This guidance was effective for the Company on January 1, 2009. The adoption of the pension and other postretirement benefits guidance required additional disclosures regarding the Company's defined benefit pension and other postretirement plans in the annual financial statements; however, it did not impact the Company's financial position or results of operations.

Modernization of Oil and Gas Reporting In January 2009, the SEC adopted final rules amending its oil and gas reporting requirements. The new rules include changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves and permitting disclosure of probable and possible reserves. The final rules were effective on December 31, 2009. For information on the impacts of adopting the SEC’s final rules for oil and gas reporting, see Supplementary Financial Information.

Financial Instruments In April 2009, the FASB issued guidance that requires disclosures about the fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements, which was effective for the Company in the second quarter of 2009. The adoption of the financial instruments guidance required additional disclosures regarding the Company’s fair value of financial instruments; however, it did not impact the Company’s financial position or results of operations.

Subsequent Events In May 2009, the FASB issued subsequent events guidance which establishes standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In addition it requires disclosure of the date through which the Company has evaluated subsequent events and whether it represents the date the financial statements were issued or were available to be issued. This guidance was effective for the Company on June 30, 2009. The adoption of the subsequent events guidance did not have a material effect on the Company’s financial position or results of operations.

Variable Interest Entities In June 2009, the FASB issued guidance related to variable interest entities which changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting rights should be consolidated and modifies the approach for determining the primary beneficiary of a variable interest entity. This guidance will require a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. The guidance related to variable interest entities was effective for the Company on January 1, 2010. The adoption of this guidance did not have a material effect on the Company’s financial position or results of operations.

Oil and Gas Reserve Estimation and Disclosure In January 2010, the FASB issued guidance related to oil and gas reserve estimation and disclosure requirements, which aligned the current oil and gas reserve estimation and disclosures with those of the SEC’s final rule, Modernization of Oil and Gas Reporting, and requires disclosure in the first annual period of the estimated effect of the initial application of the guidance. The guidance related to oil and gas reserve estimation and disclosure was effective for the Company on December 31, 2009. For more information on the effects of adopting the oil and gas reserve estimation and disclosure guidance, see Supplementary Financial Information.

Improving Disclosure About Fair Value Measurements In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods and were effective for the Company on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. The guidance will require additional disclosures but will not impact the Company's financial position or results of operations.

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 on available-for-sale investments. For more information on derivative instruments, see Note 7.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2009, 2008 and 2007, were as follows:

	2009	2008	2007
		(In thousands)	
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 $(2,509), $30,414 and $3,989 in 2009, 2008 and 2007, respectively	$(4,094)	$49,623	$6,508
Less: Reclassification adjustment for gain on derivative instruments included in net income, net of tax of $29,170, $3,795 and $12,504 in 2009, 2008 and 2007, respectively	47,590	6,175	20,013
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(51,684)	43,448	(13,505)
Postretirement liability adjustment, net of tax of $6,291, $(8,750) and $1,835 in 2009, 2008 and 2007, respectively	9,918	(13,751)	3,012
Foreign currency translation adjustment, net of tax of $6,814, $(6,108) and $3,606 in 2009, 2008 and 2007, respectively	10,568	(9,534)	7,177
Net unrealized gain on available-for-sale investments, net of tax of $270 in 2007	—	—	405
Total other comprehensive income (loss)	$(31,198)	$20,163	$(2,911)

The after-tax components of accumulated other comprehensive income (loss) as of December 31, 2009, 2008 and 2007, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain on Available-for-sale Investments	Total Accumulated Other Comprehensive Income (Loss)
	(In thousands)				
Balance at December 31, 2007	$5,938	$(21,330)	$5,594	$ 405	$ (9,393)
Balance at December 31, 2008	$49,386	$(35,081)	$(3,940)	$ —	$ 10,365
Balance at December 31, 2009	$(2,298)	$(25,163)	$6,628	$ —	$ (20,833)

Note 2 – Acquisitions

In 2009, the Company acquired a pipeline and energy services business in Montana which was not material. The total purchase consideration for this business and purchase price adjustments with respect to certain other acquisitions made prior to 2009, consisting of the Company’s common stock and cash, was $22.0 million.

In 2008, the Company acquired a construction services business in Nevada; natural gas properties in Texas; construction materials and contracting businesses in Alaska, California, Idaho and Texas; and Intermountain, a natural gas distribution business, as discussed below. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2008, consisting of the Company’s common stock and cash and the outstanding indebtedness of Intermountain, was $624.5 million.

On October 1, 2008, the acquisition of Intermountain was finalized and Intermountain became an indirect wholly owned subsidiary of the Company. Intermountain’s service area is in Idaho.

In 2007, the Company acquired construction materials and contracting businesses in North Dakota, Texas and Wyoming; a construction services business in Nevada; and Cascade, a natural gas distribution business, as discussed below. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2007, consisting of the Company's common stock and cash and the outstanding indebtedness of Cascade, was $526.3 million.

On July 2, 2007, the acquisition of Cascade was finalized and Cascade became an indirect wholly owned subsidiary of the Company. Cascade's natural gas service areas are in Washington and Oregon.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. On the above acquisition made in 2009, a final fair market value is pending the completion of the review of the relevant assets and liabilities as of the acquisition date. 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 above acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

Note 3 – Discontinued Operations
Innovatum, a component of the pipeline and energy services segment, specialized in cable and pipeline magnetization and location. During the third quarter of 2006, the Company initiated a plan to sell Innovatum because the Company determined that Innovatum is a non-strategic asset. During the fourth quarter of 2006, the stock and a portion of the assets of Innovatum were sold and the Company sold the remaining assets of Innovatum in January 2008. The loss on disposal of Innovatum was not material.

During the fourth quarter of 2006, the Company initiated a plan to sell certain of the domestic assets of Centennial Resources. The plan to sell was based on the increased market demand for independent power production assets, combined with the Company's desire to efficiently fund future capital needs. The Company subsequently committed to a plan to sell CEM due to strong interest in the operations of CEM during the bidding process for the domestic independent power production assets in the first quarter of 2007.

In July 2007, Centennial Resources sold its domestic independent power production business consisting of Centennial Power and CEM to Bicent Power LLC (formerly known as Montana Acquisition Company LLC). The transaction was valued at $636 million, which included the assumption of approximately $36 million of project-related debt. The gain on the sale of the assets, excluding the gain on the sale of Hartwell as discussed in Note 4, was approximately $85.4 million (after tax).

The Company's consolidated financial statements and accompanying notes for prior periods present the results of operations of Innovatum and the domestic independent power production assets as discontinued operations. In addition, the assets and liabilities of these operations were treated as held for sale, and as a result, no depreciation, depletion and amortization expense was recorded from the time each of the assets was classified as held for sale.

Operating results related to Innovatum for the year ended December 31, 2007, were as follows:

	2007 (In thousands)
Operating revenues	$1,748
Loss from discontinued operations before income tax benefit	(210)
Income tax benefit	(316)
Income from discontinued operations, net of tax	$106

Operating results related to the domestic independent power production assets for the year ended December 31, 2007, were as follows:

	2007 (In thousands)
Operating revenues	$125,867
Income from discontinued operations (including gain on disposal in 2007 of $142.4 million) before income tax expense	177,666
Income tax expense	68,438
Income from discontinued operations, net of tax	$109,228

Revenues at the former independent power production operations were recognized based on electricity delivered and capacity provided, pursuant to contractual commitments and, where applicable, revenues were recognized ratably over the terms of the related contract. Arrangements

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with multiple revenue-generating activities were recognized with the multiple deliverables divided into separate units of accounting based on specific criteria and revenues of the arrangements allocated to the separate units based on their relative fair values.

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. The Company's equity method investments at December 31, 2009 and 2008, include the Brazilian Transmission Lines.

In August 2006, MDU Brasil acquired ownership interests in companies owning the Brazilian Transmission Lines. The interests involve the ENTE (13.3-percent ownership interest), ERTE (13.3-percent ownership interest) and ECTE (25-percent ownership interest) electric transmission lines, which 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 and have between 21 and 23 years remaining under the contracts. Alusa and CEMIG hold the remaining ownership interests, with CELESC also having an ownership interest in ECTE. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In the fourth quarter of 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. This sale is pending regulatory approvals. One of the parties will purchase 15.6 percent of the Company’s ownership interests over a four-year period. The other parties will purchase 84.4 percent of the Company’s ownership interests at the financial close of the transaction.

In September 2004, Centennial Resources, through indirect wholly owned subsidiaries, acquired a 50 percent ownership interest in Hartwell, which owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. In July 2007, the Company sold its ownership interest in Hartwell, and realized a gain of $10.1 million ($6.1 million after tax) from the sale which is recorded in earnings from equity method investments on the Consolidated Statements of Income.

At December 31, 2009 and 2008, the investments in which the Company held an equity method interest had total assets of $387.0 million and $294.7 million, respectively, and long-term debt of $176.7 million and $158.0 million, respectively. The Company's investment in its equity method investments was approximately $62.4 million and $44.4 million, including undistributed earnings of $9.3 million and $6.8 million, at December 31, 2009 and 2008, respectively.

Note 5 – Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2009, were as follows:

	Balance as of January 1, 2009	Goodwill Acquired During the Year*	Balance as of December 31, 2009
		(In thousands)	
Electric	$—	$—	$ —
Natural gas distribution	344,952	784	345,736
Construction services	95,619	4,508	100,127
Pipeline and energy services	1,159	6,698	7,857
Natural gas and oil production	—	—	—
Construction materials and contracting	174,005	1,738	175,743
Other	—	—	—
Total	$615,735	$13,728	$ 629,463

* Includes purchase price adjustments that were not material related to acquisitions in a prior period.

The changes in the carrying amount of goodwill for the year ended December 31, 2008, were as follows:

	Balance as of January 1, 2008	Goodwill Acquired During the Year*	Balance as of December 31, 2008
		(In thousands)	
Electric	$—	$—	$ —
Natural gas distribution	171,129	173,823	344,952
Construction services	91,385	4,234	95,619
Pipeline and energy services	1,159	—	1,159
Natural gas and oil production	—	—	—
Construction materials and contracting	162,025	11,980	174,005
Other	—	—	—
Total	$425,698	$190,037	$ 615,735

* Includes purchase price adjustments that were not material related to acquisitions in a prior period.

Other amortizable intangible assets at December 31 were as follows:

	2009	2008
	(In thousands)	
Customer relationships	$24,942	$21,842
Accumulated amortization	(9,500)	(6,985)
	15,442	14,857
Noncompete agreements	12,377	10,080
Accumulated amortization	(6,675)	(5,126)
	5,702	4,954
Other	10,859	10,949
Accumulated amortization	(3,026)	(2,368)
	7,833	8,581
Total	$28,977	$28,392

Amortization expense for intangible assets for the years ended December 31, 2009, 2008 and 2007, was $5.0 million, $5.1 million and $4.4 million, respectively. Estimated amortization expense for intangible assets is $4.5 million in 2010, $4.0 million in 2011, $3.9 million in 2012, $3.4 million in 2013, $3.0 million in 2014 and $10.2 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:

	2009	2008
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefits (a)	$91,078	$119,868
Deferred income taxes*	85,712	46,855
Natural gas supply derivatives (a) (b)	27,900	89,813
Costs related to potential generation development (a)	15,499	—
Long-term debt refinancing costs (a)	12,089	9,991
Taxes recoverable from customers (a)	10,102	4,824
Plant costs (a)	7,775	8,534
Natural gas cost recoverable through rate adjustments (b)	982	51,699
Other (a) (b)	12,242	7,978
Total regulatory assets	263,379	339,562
Regulatory liabilities:		
Plant removal and decommissioning costs (c)	251,143	94,737
Deferred income taxes*	53,835	65,909
Natural gas costs refundable through rate adjustments (d)	37,356	64
Taxes refundable to customers (c)	34,571	25,642
Natural gas supply derivatives (c)	—	5,540
Other (c) (d)	17,767	7,460
Total regulatory liabilities	394,672	199,352
Net regulatory position	$(131,293)	$140,210

*Represents deferred income taxes related to regulatory assets and liabilities.

(a) Included in deferred charges and other assets 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.

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. In 2009, the Company determined that plant removal costs related to recent acquisitions should be reclassified from accumulated depreciation to a regulatory liability. This reclassification is reflected in the preceding table.

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, 2009, the Company had no outstanding foreign currency or interest rate hedges.

Cascade and Intermountain
At December 31, 2009, Cascade and Intermountain held natural gas swap agreements, with total forward notional volumes of 12.1 million MMBtu, which were not designated as hedges. Cascade and Intermountain utilize natural gas swap agreements to manage a portion of their regulated natural gas supply portfolios in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the IPUC, WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Cascade and Intermountain record periodic changes in the fair market value of the derivative instruments on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade and Intermountain will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the year ended December 31, 2009, Cascade and Intermountain recorded the decrease in the fair market value of the derivative instruments of $61.9 million in regulatory assets.

Certain of Cascade's derivative instruments contain credit-risk-related contingent features that permit the counterparties to require collateralization if Cascade's derivative liability positions exceed certain dollar thresholds. The dollar thresholds in certain of Cascade's agreements are determined and may fluctuate based on Cascade's credit rating on its debt. In addition, Cascade's and Intermountain's derivative instruments contain cross-default provisions that state if the entity fails to make payment with respect to certain of its indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of such entity's derivative instruments in liability positions. The aggregate fair value of Cascade and Intermountain's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2009, was $27.9 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2009, was $27.9 million.

Fidelity
At December 31, 2009, Fidelity held natural gas swaps and collar agreements with total forward notional volumes of 26.5 million MMBtu, natural gas basis swaps with total forward notional volumes of 15.1 million MMBtu, and oil swaps and collar agreements with total forward notional volumes of 2.0 million Bbl, all of which were designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on its forecasted sales of natural gas and oil production.

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. 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). At the date the natural gas and oil quantities are settled, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings. The proceeds received for natural gas and oil production are generally based on market prices.

For the years ended December 31, 2009, 2008 and 2007, the amount of hedge ineffectiveness was immaterial, and 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. There were no such reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in operating revenues on the Consolidated Statements of Income. For further information regarding the gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in other comprehensive income (loss) and the gains and losses reclassified from accumulated other comprehensive income (loss) into earnings, see Note 1.

As of December 31, 2009, the maximum term of the swap and collar agreements, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 24 months. The Company estimates that over the next 12 months net losses of approximately $3.8 million (after tax) will be reclassified from accumulated other comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Certain of Fidelity's derivative instruments contain cross-default provisions that state if Fidelity 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 derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2009, was $13.9 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2009, was $13.9 million.

The location and fair value of all of the Company’s derivative instruments on the Consolidated Balance Sheets as of December 31, 2009, were as follows:

	Asset Derivatives Location on Consolidated Balance Sheets	Fair Value	Liability Derivatives Location on Consolidated Balance Sheets	Fair Value
		(In thousands)		
Commodity derivatives designated as hedges:				
	Commodity derivative instruments	$7,761	Commodity derivative instruments	$13,763
	Other assets - noncurrent	2,734	Other liabilities – noncurrent	114
Total derivatives designated as hedges		10,495		13,877
Commodity derivatives not designated as hedges:				
	Commodity derivative instruments	—	Commodity derivative instruments	23,144
	Other assets - noncurrent	—	Other liabilities – noncurrent	4,756
Total derivatives not designated as hedges		—		27,900
Total derivatives		$10,495		$41,777

Note 8 – Fair Value Measurements

On January 1, 2008, the Company elected to measure its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. These investments had previously been accounted for as available-for-sale investments. The Company anticipates using these investments 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 $34.8 million and $27.7 million as of December 31, 2009 and 2008, respectively, are classified as Investments on the Consolidated Balance Sheets. The increase in the fair value of these investments for the year ended December 31, 2009, was $7.1 million (before tax). The decrease in the fair value of these investments for the year ended December 31, 2008, was $8.6 million (before tax). 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 for its remaining available-for-sale securities, which are auction rate securities. The Company’s auction rate securities, which totaled $11.4 million at December 31, 2009 and 2008, are accounted for as available-for-sale and are recorded at fair value. The fair value of the auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments.

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 statement establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The Company’s assets and liabilities measured at fair value on a recurring basis are as follows:

	Fair Value Measurements at December 31, 2009, Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Collateral Provided to Counterparties	Balance at December 31, 2009
			(In thousands)		
Assets:					
Money market funds	$9,124	$151,000	$ —	$ —	$ 160,124
Available-for-sale securities	9,078	37,141	—	—	46,219
Commodity derivative instruments - current	—	7,761	—	—	7,761
Commodity derivative instruments - noncurrent	—	2,734	—	—	2,734
Total assets measured at fair value	$18,202	$198,636	$ —	$ —	$ 216,838
Liabilities:					
Commodity derivative instruments - current	$—	$36,907	$ —	$ —	$ 36,907
Commodity derivative instruments - noncurrent	—	4,870	—	—	4,870
Total liabilities measured at fair value	$—	$41,777	$ —	$ —	$ 41,777

	Fair Value Measurements at December 31, 2008, Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Collateral Provided to Counterparties	Balance at December 31, 2008
			(In thousands)		
Assets:					
Available-for-sale securities	$27,725	$11,400	$ —	$ —	$ 39,125
Commodity derivative instruments - current	—	78,164	—	—	78,164
Commodity derivative instruments - noncurrent	—	3,222	—	—	3,222
Total assets measured at fair value	$27,725	$92,786	$ —	$ —	$ 120,511
Liabilities:					
Commodity derivative instruments - current	$—	$67,629	$ —	$ 11,100	$ 56,529
	—	23,534	—	—	23,534

Commodity derivative instruments - noncurrent					
Total liabilities measured at fair value	$—	$91,163	$ —	$ 11,100	$ 80,063

The estimated fair value of the Company's Level 1 money market funds is valued at the net asset value of shares held by the Company, based on published market quotations in active markets. The estimated fair value of the Company's Level 1 available-for-sale securities is based on quoted market prices in active markets for identical equity and fixed-income securities. The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is based on comparable market transactions or underlying investments. 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.

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 estimated fair value of the Company’s long-term debt was based on quoted market prices of the same or similar issues. The estimated fair value of the Company's long-term debt at December 31 was as follows:

	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$1,499,306	$1,566,331	$1,647,302	$1,577,907

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 below, 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, 2009. 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 credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit		Amount Outstanding at December 31, 2009		Amount Outstanding at December 31, 2008		Letters of Credit at December 31, 2009		Expiration Date	
				(Dollars in millions)							
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$125.0		$ —	(b)	$ 22.5	(b)	$ —		6/21/11	
MDU Energy Capital, LLC	Master shelf agreement	$175.0		$ 165.0		$ 165.0		$ —		8/14/10	(c)
Cascade Natural Gas Corporation	Revolving credit agreement	$50.0	(d)	$ —		$ 48.1		$ 1.9	(e)	12/28/12	(f)
Intermountain Gas Company	Revolving credit agreement	$65.0	(g)	$ 10.3		$ 36.5		$ —		8/31/10	
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (h)	$400.0		$ —	(b)	$ 150.0	(b)	$ 26.4	(e)	12/13/12	
Williston Basin Interstate Pipeline Company	Uncommitted long-term private shelf agreement	$125.0		$ 87.5		$ 72.5		$ —		12/23/10	(i)

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (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) Or such time as the agreement is terminated by either of the parties thereto.
(d) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(e) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.
(f) Provisions allow for an extension of up to two years upon consent of the banks.
(g) Certain provisions allow for increased borrowings, up to a maximum of $70 million.
(h) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.
(i) Certain provisions allow for an extension to December 23, 2011.

In order to maintain the Company’s and Centennial’s respective commercial paper programs in the amounts indicated above, both the Company and Centennial must have revolving credit agreements in place at least equal to the amount of their commercial paper programs. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings
MDU Resources Group, Inc. The Company had $57.0 million outstanding under a $175 million term loan agreement at December 31, 2008. This agreement expired on March 24, 2009.

Cascade Natural Gas Corporation Any borrowings under the $50 million revolving credit agreement would be classified as short-term borrowings as Cascade intends to repay the borrowings within one year.

Cascade’s 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. 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 credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Intermountain Gas Company The weighted average interest rate for borrowings outstanding under the credit agreement at December 31, 2009, was 3.25 percent. The credit agreement contains customary covenants and provisions, including covenants of Intermountain 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 Intermountain's earnings before interest, taxes, depreciation and amortization to interest expense (determined on a consolidated basis), for the 12-month period ended each fiscal quarter, to be less than 2 to 1. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (i) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of $5 million, (ii) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (iii) certain conditions result in an early termination date under any swap contract, then Intermountain shall 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. The commercial paper borrowings 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 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. Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company alone, excluding its subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. Other covenants include restrictions on the sale of certain assets and on the making of certain investments.

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

In November 2009, the Company completed a defeasance of its outstanding 8.60% Secured Medium-Term Notes, Series A, due April 1, 2012 (8.60% Notes), by depositing approximately $5.5 million with the Mortgage trustee. The $5.5 million deposit will be used solely to satisfy the principal and remaining interest obligations on the 8.60% Notes. These securities are the only remaining first mortgage bonds outstanding under the Mortgage, other than $30.0 million of first mortgage bonds which were held by the Indenture trustee for the benefit of the senior note holders. In connection with the defeasance of the 8.60% Notes, the Mortgage was discharged and the lien of the Indenture was discharged so that the Company's 5.98% Senior Notes due 2033 are now unsecured.

MDU Energy Capital, LLC 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).

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. The Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings.

Centennial's credit agreement and the Centennial uncommitted long-term master shelf agreement contain customary covenants and provisions, including 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 65 percent (for the $400 million credit agreement) and 60 percent (for the master shelf agreement). The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments.

Pursuant to a covenant under the 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 for the immediately preceding fiscal year. The write-down of the natural gas and oil properties in 2009 would have negatively affected Centennial's ability to make distributions to the Company in 2010, however, in November 2009, the lenders under the credit agreement consented to permit Centennial to make distributions during 2010 in an aggregate amount up to 100 percent of its consolidated net income after taxes during fiscal year 2009 without giving effect to the write-down.

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. Certain of Centennial's financing agreements and Centennial's practices limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company The uncommitted long-term private shelf agreement contains customary covenants and provisions, including a covenant of Williston Basin 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 limitation on priority debt and some 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:

	2009	2008	
	(In thousands)		
First mortgage bonds and notes:			
Secured Medium-Term Notes, Series A, 8.60%	$ —	$ 5,500	
Senior Notes, 5.98%, due December 15, 2033	—	30,000	(a)
Total first mortgage bonds and notes	—	35,500	
Senior Notes at a weighted average rate of 6.07%, due on dates ranging from October 30, 2010 to March 8, 2037	1,370,455	1,271,227	
Commercial paper supported by revolving credit agreements	—	172,500	
Medium-Term Notes at a weighted average rate of 7.72%, due on dates ranging from September 4, 2012 to March 16, 2029	81,000	81,000	
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	42,070	42,971	
Credit agreements at a weighted average rate of 5.67%, due on dates ranging from April 1, 2010 to November 30, 2038	5,781	44,205	
Discount	—	(101)	
Total long-term debt	1,499,306	1,647,302	
Less current maturities	12,629	78,666	
Net long-term debt	$ 1,486,677	$ 1,568,636	

(a) The $30.0 million of 5.98% Senior Notes became unsecured upon the defeasance of the outstanding 8.60% Notes, as previously discussed.

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2009, aggregate $12.6 million in 2010; $72.3 million in 2011; $136.3 million in 2012; $258.8 million in 2013; $9.1 million in 2014 and $1,010.2 million thereafter.

Note 10 – Asset Retirement Obligations

The Company records obligations related to the plugging and abandonment of natural gas and oil 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 and transmission facilities and buildings, and certain other obligations associated with leased properties.

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

	2009	2008
	(In thousands)	
Balance at beginning of year	$70,147	$64,453
Liabilities incurred	2,418	2,943
Liabilities acquired	—	2,369
Liabilities settled	(9,319)	(3,188)
Accretion expense	3,385	3,191
Revisions in estimates	9,548	207
Other	180	172
Balance at end of year	$76,359	$70,147

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, 2009 and 2008, was $5.9 million.

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

	2009	2008
	(Dollars in thousands)	
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

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

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 2007 through March 2007 and October 1, 2008 through October 21, 2008, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From April 2007 through September 30, 2008, and October 22, 2008 through December 2009, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2009, there were 23.2 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 state laws, applicable regulatory limitations, and compliance with the requirements of the Company’s credit agreements. 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 and is authorized to grant options, restricted stock and stock for up to 16.9 million shares of common stock and has granted options, restricted stock and stock of 7.3 million shares through December 31, 2009. The Company generally issues new shares of common stock to satisfy stock option exercises, restricted stock, stock and performance share awards.

Total stock-based compensation expense was $3.4 million, net of income taxes of $2.2 million in 2009; $3.7 million, net of income taxes of $2.3 million in 2008; and $4.7 million, net of income taxes of $3.1 million in 2007.

As of December 31, 2009, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.6 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock options

The Company has stock option plans for directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expire 10 years after the date

of grant. Options granted to directors and employees vest at the date of grant and three years after the date of grant, respectively, and expire 10 years after the date of grant.

The fair value of each option outstanding was estimated on the date of grant using the Black-Scholes option-pricing model.

A summary of the status of the stock option plans at December 31, 2009, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	1,003,824	$13.39
Forfeited	(24,188)	13.22
Exercised	(154,765)	13.23
Balance at end of year	824,871	13.42
Exercisable at end of year	799,703	$13.41

Summarized information about stock options outstanding and exercisable as of December 31, 2009, was as follows:

	Options Outstanding				Options Exercisable		
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)	Number Exercisable	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)
$ 9.61 – 12.00	12,131	.5	$9.93	$ 166	12,131	$9.93	$ 166
12.01 – 14.50	745,970	1.2	13.21	7,751	726,235	13.21	7,545
14.51 – 17.13	66,770	1.2	16.48	475	61,337	16.51	435
Balance at end of year	824,871	1.2	$13.42	$ 8,392	799,703	$13.41	$ 8,146

The aggregate intrinsic value in the preceding table represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2009, which would have been received by the option holders had all option holders exercised their options as of that date.

The weighted average remaining contractual life of options exercisable was 1.2 years at December 31, 2009.

The Company received cash of $2.1 million, $5.9 million and $10.2 million from the exercise of stock options for the years ended December 31, 2009, 2008 and 2007, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007, was $1.3 million, $8.1 million and $11.2 million, respectively.

Restricted stock awards

Prior to 2002, the Company granted restricted stock awards under a long-term incentive plan. The restricted stock awards granted vest at various times ranging from one year to nine years from the date of issuance, but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the Company. The grant-date fair value is the market price of the Company's stock on the grant date.

A summary of the status of the restricted stock awards for the year ended December 31, 2009, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	20,606	$13.22
Vested	—	—
Forfeited	(2,970)	13.22
Nonvested at end of period	17,636	$13.22

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 49,649 shares with a fair value of $879,000, 45,675 shares with a fair value of $1.2 million and 48,228 shares with a fair value of $1.5 million issued under this plan during the years ended December 31, 2009, 2008 and 2007, respectively.

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

Target grants of performance shares outstanding at December 31, 2009, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2007	2007-2009	175,596
February 2008	2008-2010	183,102
February 2009	2009-2011	275,807

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. The grant-date fair value of performance share awards granted during the years ended December 31, 2009, 2008 and 2007, was $20.39, $30.71 and $23.55, per share, respectively. The grant-date fair value for the performance shares was determined by Monte Carlo simulation using a blended volatility term structure in the range of 40.40 percent to 50.98 percent in 2009, 21.54 percent to 22.97 percent in 2008 and 18.17 percent to 18.73 percent in 2007 comprised of 50 percent historical volatility and 50 percent implied volatility and a risk-free interest rate term structure in the range of .30 percent to 1.36 percent in 2009, 1.87 percent to 2.23 percent in 2008 and 4.75 percent to 5.21 percent in 2007 based on U.S. Treasury security rates in effect as of the grant date. In addition, the mean over all simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was $1.79, $1.64 and $1.25 per target share for the 2009, 2008 and 2007 awards, respectively. The fair value of performance share awards that vested during the years ended December 31, 2009, 2008 and 2007, was $2.8 million, $8.5 million and $6.0 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2009, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	546,867	$26.55
Granted	278,178	20.39
Vested	(151,848)	25.22
Forfeited	(38,692)	25.35
Nonvested at end of period	634,505	$24.24

Note 14 – Income Taxes

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

	2009	2008	2007
		(In thousands)	
United States	$(227,021)	$436,029	$508,210
Foreign	7,655	5,120	4,600
Income (loss) before income taxes	$(219,366)	$441,149	$512,810

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

	2009	2008	2007
		(In thousands)	
Current:			
Federal	$64,389	$82,279	$106,399
State	8,284	(184)	15,135
Foreign	254	(104)	235
	72,927	81,991	121,769
Deferred:			
Income taxes –			
Federal	(147,607)	59,963	58,030
State	(22,370)	5,332	9,656
Investment tax credit – net	213	(405)	(414)
	(169,764)	64,890	67,272
Change in uncertain tax benefits	562	422	869
Change in accrued interest	183	173	114
Total income tax expense (benefit)	$(96,092)	$147,476	$190,024

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

	2009	2008
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$85,712	$46,855
Accrued pension costs	79,052	93,371
Asset retirement obligations	24,091	22,707
Deferred compensation	11,411	12,015
Other	59,763	62,456
Total deferred tax assets	260,029	237,404
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	601,426	562,326
Basis differences on natural gas and oil producing properties	116,521	284,231
Regulatory matters	53,835	65,909
Natural gas and oil price swap and collar agreements	—	30,414
Other	51,070	42,725
Total deferred tax liabilities	822,852	985,605
Net deferred income tax liability	$(562,823)	$(748,201)

As of December 31, 2009 and 2008, no valuation allowance has been recorded associated with the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2008, to December 31, 2009, to deferred income tax benefit:

	2009
	(In thousands)
Change in net deferred income tax liability from the preceding table	$(185,378)
Deferred taxes associated with other comprehensive loss	18,574
Deferred taxes associated with acquisitions	762
Other	(3,722)
Deferred income tax benefit for the period	$(169,764)

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,	2009		2008		2007	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$(76,778)	35.0	$154,402	35.0	$179,484	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	(7,280)	3.3	10,709	2.4	17,121	3.3
Deductible K-Plan dividends	(2,369)	1.1	(2,144)	(.5)	(2,134)	(.4)
Depletion allowance	(2,320)	1.0	(2,932)	(.7)	(4,073)	(.8)
Federal renewable energy credit	(1,452)	.7	(1,235)	(.3)	—	—
Foreign operations	(1,148)	.5	423	.1	9,603	1.8
Domestic production activities deduction	(856)	.4	(3,031)	(.7)	(4,787)	(.9)
Resolution of tax matters and uncertain tax positions	881	(.4)	595	.1	208	—
Other	(4,770)	2.2	(9,311)	(2.0)	(5,398)	(.9)
Total income tax expense (benefit)	$(96,092)	43.8	$147,476	33.4	$190,024	37.1

The income tax benefit in 2009 resulted largely from the Company’s write-down of natural gas and oil properties, as discussed in Note 1.

Prior to the sale of the domestic independent power production assets on July 10, 2007, as discussed in Note 3, the Company considered earnings (including the gain from the sale of its foreign equity method investment in a natural gas-fired electric generating facility in Brazil in 2005) to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes were recorded with respect to such earnings. Following the sale of these assets, the Company reconsidered its long-term plans for future development and expansion of its foreign investment and has determined that it has no immediate plans to explore or invest in additional foreign investments at this time. Therefore in the third quarter of 2007, deferred income taxes were accrued with respect to the temporary differences which had not been previously recorded. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $36.8 million at December 31, 2009. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2009, was approximately $10.5 million, which was largely recognized in 2007. Future earnings will also be subject to additional U.S. taxes, net of allowable foreign tax credits.

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 2004.

On January 1, 2007, upon the adoption of accounting guidance related to uncertain tax positions, the Company recognized a decrease in the liability for unrecognized tax benefits, which was not material and was accounted for as an increase to the January 1, 2007, balance of retained earnings. At the date of adoption, the amount of unrecognized tax benefits was $4.5 million, including interest.

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

	2009	2008	2007
		(In thousands)	
Balance at beginning of year	$5,586	$3,735	$4,241
Additions based on tax positions related to the current year	—	1,102	373
Additions for tax positions of prior years	562	1,811	588
Reductions for tax positions of prior years	—	(1,062)	—
Lapse of statute of limitations	—	—	(1,467)
Balance at end of year	$6,148	$5,586	$3,735

Included in the balance of unrecognized tax benefits at December 31, 2009, were $540,000 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 at December 31, 2009, was $6.4 million, including approximately $804,000 for the payment of interest and penalties.

The Company does not anticipate the amount of unrecognized tax benefits to significantly increase or decrease within the next 12 months.

For the years ended December 31, 2009, 2008 and 2007, the Company recognized approximately $190,000, $819,000 and $680,000, respectively, in interest expense. Penalties were not material in 2009, 2008 and 2007. The Company recognized interest income of approximately $165,000, $223,000 and $480,000 for the years ended December 31, 2009, 2008 and 2007, respectively. The Company had accrued liabilities of approximately $1.6 million, $1.4 million and $718,000 at December 31, 2009, 2008 and 2007, respectively, for the payment of interest.

Note 15 – Business Segment Data

The Company’s reportable segments are those that are based on the Company’s method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The vast majority of the Company’s operations are located within the United States. The Company also has investments in foreign countries, which largely consist of Centennial Resources’ equity method investment in the Brazilian Transmission Lines.

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 products and services.

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 pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and energy-related services.

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

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 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 and automobile liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes Centennial Resources' equity method investment in the Brazilian Transmission Lines.

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:

	2009	2008	2007
		(In thousands)	
External operating revenues:			
Electric	$196,171	$208,326	$193,367
Natural gas distribution	1,072,776	1,036,109	532,997
Pipeline and energy services	235,322	440,764	369,345
	1,504,269	1,685,199	1,095,709
Construction services	818,685	1,256,759	1,102,566
Natural gas and oil production	338,425	420,637	288,148
Construction materials and contracting	1,515,122	1,640,683	1,761,473
Other	—	—	—
	2,672,232	3,318,079	3,152,187
Total external operating revenues	$4,176,501	$5,003,278	$4,247,896

Intersegment operating revenues:			
Electric	$—	$—	$—
Natural gas distribution	—	—	—
Construction services	379	560	649
Pipeline and energy services	72,505	91,389	77,718
Natural gas and oil production	101,230	291,642	226,706
Construction materials and contracting	—	—	—
Other	9,487	10,501	10,061
Intersegment eliminations	(183,601)	(394,092)	(315,134)
Total intersegment operating revenues	$—	$—	$—
Depreciation, depletion and amortization:			
Electric	$24,637	$24,030	$22,549
Natural gas distribution	42,723	32,566	19,054
Construction services	12,760	13,398	14,314
Pipeline and energy services	25,581	23,654	21,631
Natural gas and oil production	129,922	170,236	127,408
Construction materials and contracting	93,615	100,853	95,732
Other	1,304	1,283	1,244
Total depreciation, depletion and amortization	$330,542	$366,020	$301,932
Interest expense:			
Electric	$9,577	$8,674	$6,737
Natural gas distribution	30,656	24,004	13,566
Construction services	4,490	4,893	4,878
Pipeline and energy services	8,896	8,314	8,769
Natural gas and oil production	10,621	12,428	8,394
Construction materials and contracting	20,495	24,291	23,997
Other	43	374	10,717
Intersegment eliminations	(679)	(1,451)	(4,821)
Total interest expense	$84,099	$81,527	$72,237
Income taxes:			
Electric	$8,205	$8,225	$8,528
Natural gas distribution	16,331	18,827	6,477
Construction services	15,189	26,952	26,829
Pipeline and energy services	22,982	15,427	18,524
Natural gas and oil production	(187,000)	68,701	78,348
Construction materials and contracting	25,940	8,947	39,045
Other	2,261	397	12,273
Total income taxes	$(96,092)	$147,476	$190,024

Earnings (loss) on common stock:			
Electric	$24,099	$18,755	$17,700
Natural gas distribution	30,796	34,774	14,044
Construction services	25,589	49,782	43,843
Pipeline and energy services	37,845	26,367	31,408
Natural gas and oil production	(296,730)	122,326	142,485
Construction materials and contracting	47,085	30,172	77,001
Other	7,357	10,812	(4,380)
Earnings (loss) on common stock before income from discontinued operations	(123,959)	292,988	322,101
Income from discontinued operations, net of tax	—	—	109,334
Total earnings (loss) on common stock	$(123,959)	$292,988	$431,435
Capital expenditures:			
Electric	$115,240	$72,989	$91,548
Natural gas distribution	43,820	398,116	500,178
Construction services	12,814	24,506	18,241
Pipeline and energy services	70,168	42,960	39,162
Natural gas and oil production	183,140	710,742	283,589
Construction materials and contracting	26,313	127,578	189,727
Other	3,196	774	1,621
Net proceeds from sale or disposition of property	(26,679)	(86,927)	(24,983)
Net capital expenditures before discontinued operations	428,012	1,290,738	1,099,083
Discontinued operations	—	—	(548,216)
Total net capital expenditures	$428,012	$1,290,738	$550,867
Assets:			
Electric*	$569,666	$479,639	$428,200
Natural gas distribution*	1,588,144	1,548,005	942,454
Construction services	328,895	476,092	456,564
Pipeline and energy services	538,230	506,872	500,755
Natural gas and oil production	1,137,628	1,792,792	1,299,406
Construction materials and contracting	1,449,469	1,552,296	1,642,729
Other**	378,920	232,149	322,326
Total assets	$5,990,952	$6,587,845	$5,592,434

Property, plant and equipment:			
Electric*	$941,791	$848,725	$784,705
Natural gas distribution*	1,456,208	1,429,487	948,446
Construction services	116,236	111,301	101,935
Pipeline and energy services	675,199	640,921	600,712
Natural gas and oil production	2,028,794	2,477,402	1,923,899
Construction materials and contracting	1,514,989	1,524,029	1,538,716
Other	33,365	30,372	31,833
Less accumulated depreciation, depletion and amortization	2,872,465	2,761,319	2,270,691
Net property, plant and equipment	$3,894,117	$4,300,918	$3,659,555

* 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 a $620.0 million ($384.4 million after tax) and $135.8 million ($84.2 million after tax) noncash write-down of natural gas and oil properties in 2009 and 2008, respectively.

The pipeline and energy services segment and the Other category recognized income from discontinued operations, net of tax, of $106,000 and $109.2 million, respectively for the year ended December 31, 2007.

Excluding income from discontinued operations at pipeline and energy services, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from construction services, natural gas and oil production, construction materials and contracting, and other are all from nonregulated operations.

Capital expenditures for 2009, 2008 and 2007 include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions and the outstanding indebtedness related to the 2008 Intermountain acquisition and the 2007 Cascade acquisition. The net noncash transactions were immaterial in 2009, $97.6 million in 2008 and $217.3 million in 2007.

Note 16 – Employee 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.

Effective January 1, 2006, the Company discontinued defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005. These employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. In 2009, the Company evaluated several provisions of its employee defined benefit plans for nonunion and certain union employees. As a result of this evaluation, the Company determined that, effective January 1, 2010, all benefit and service accruals of these plans 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. Current 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.

Changes in benefit obligation and plan assets for the year ended December 31, 2009 and 2008, and amounts recognized in the Consolidated Balance Sheets at December 31, 2009 and 2008, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$358,525	$359,923	$94,325	$81,581
Service cost	8,127	8,812	2,206	1,977
Interest cost	21,919	21,264	5,465	5,079
Plan participants' contributions	—	—	2,369	2,120
Amendments	—	—	(9,319)	(382)
Actuarial (gain) loss	26,188	(8,336)	813	763
Curtailment gain	(38,166)	—	—	—
Acquisition	—	—	—	9,872
Benefits paid	(23,678)	(23,138)	(7,708)	(6,685)
Benefit obligation at end of year	352,915	358,525	88,151	94,325
Change in net plan assets:				
Fair value of plan assets at beginning of year	226,214	330,966	60,085	73,684
Actual gain (loss) on plan assets	42,084	(83,960)	8,600	(20,058)
Employer contribution	10,707	2,346	3,638	3,212
Plan participants' contributions	—	—	2,369	2,120
Acquisition	—	—	—	7,812
Benefits paid	(23,678)	(23,138)	(7,708)	(6,685)
Fair value of net plan assets at end of year	255,327	226,214	66,984	60,085
Funded status – under	$(97,588)	$(132,311)	$(21,167)	$(34,240)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	$—	$—	$(459)	$(407)
Other liabilities (noncurrent)	(97,588)	(132,311)	(20,708)	(33,833)
Net amount recognized	$(97,588)	$(132,311)	$(21,167)	$(34,240)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	$99,985	$131,081	$20,134	$23,418
Prior service cost (credit)	430	2,685	(14,716)	(8,151)
Transition obligation	—	—	6,378	8,503
Total	$100,415	$133,766	$11,796	$23,770

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.

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

The accumulated benefit obligation for the defined benefit pension plans reflected above was $340.3 million and $312.1 million at December 31, 2009 and 2008, respectively.

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

	2009	2008
	(In thousands)	
Projected benefit obligation	$352,915	$358,525
Accumulated benefit obligation	$340,341	$312,110
Fair value of plan assets	$255,327	$226,214

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		
	2009	2008	2007	2009	2008	2007
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	$8,127	$8,812	$9,098	$2,206	$1,977	$1,865
Interest cost	21,919	21,264	18,591	5,465	5,079	4,212
Expected return on assets	(25,062)	(26,501)	(22,524)	(5,471)	(5,657)	(4,776)
Amortization of prior service cost (credit)	605	665	756	(2,756)	(2,755)	(1,300)
Recognized net actuarial loss	2,096	1,050	1,605	970	594	73
Curtailment loss	1,650	—	—	—	—	—
Amortization of net transition obligation	—	—	—	2,125	2,125	2,125
Net periodic benefit cost, including amount capitalized	9,335	5,290	7,526	2,539	1,363	2,199
Less amount capitalized	1,127	642	991	330	307	373
Net periodic benefit cost	8,208	4,648	6,535	2,209	1,056	1,826
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	(29,000)	102,125	(11,095)	(2,314)	26,478	1,507
Acquisition-related actuarial loss	—	—	12,291	—	—	9,818
Prior service credit	—	—	—	(9,321)	(382)	—
Acquisition-related prior service credit	—	—	(1,842)	—	—	(12,472)
Amortization of actuarial loss	(2,096)	(1,050)	(1,605)	(970)	(594)	(73)
Amortization of prior service (cost) credit	(2,255)	(665)	(756)	2,756	2,755	1,300
Amortization of net transition obligation	—	—	—	(2,125)	(2,125)	(2,125)
	(33,351)	100,410	(3,007)	(11,974)	26,132	(2,045)

Total recognized in accumulated other comprehensive (income) loss						
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	$(25,143)	$105,058	$3,528	$(9,765)	$27,188	$(219)

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 2010 are $2.4 million and $152,000, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2010 are $1.0 million, $3.5 million and $2.1 million, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
Discount rate	5.75 %	6.25 %	5.75 %	6.25 %
Rate of compensation increase	4.00 %	4.00 %	4.00 %	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	
	2009	2008	2009	2008
Discount rate	6.25 %	6.00 %	6.25 %	6.00 %
Expected return on plan assets	8.50 %	8.50 %	7.50 %	7.50 %
Rate of compensation increase	4.00 %	4.20 %	4.00 %	4.50 %

The expected rate of return on plan assets is based on the targeted asset allocation of 70 percent equity securities and 30 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:

	2009	2008
Health care trend rate assumed for next year	6.0%-9.0 %	6.0%-9.0 %
Health care cost trend rate – ultimate	5.0%-6.0 %	5.0%-6.0 %
Year in which ultimate trend rate achieved	1999-2017	1999-2017

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee'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 6 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, 2009:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$91	$ (922)
Effect on postretirement benefit obligation	$2,435	$ (9,679)

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The Company's pension assets are managed by 12 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 future 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.

The fair value of the Company's pension net plan assets by category is as follows:

	Fair Value Measurements at December 31, 2009, 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, 2009
	(In thousands)			
Assets:				
Common stocks (a)	$133,989	$—	$ —	$133,989
Collective and mutual funds (b)	39,234	10,379	—	49,613
U.S. government and U.S. government-sponsored securities (c)	—	28,091	—	28,091
Corporate and municipal bonds (d)	—	27,968	—	27,968
Collateral held on loaned securities (e)	—	21,597	937	22,534
Cash and cash equivalents	17,958	—	—	17,958
Total assets measured at fair value	191,181	88,035	937	280,153
Liabilities:				
Obligation for collateral received	24,826	—	—	24,826
Net assets measured at fair value	$166,355	$88,035	$ 937	$255,327

(a) This category includes approximately 75 percent U.S. common stocks and 25 percent non-U.S. common stocks.

(b) Collective and mutual funds invest approximately 43 percent in common stock of large-cap U.S. companies, 21 percent in asset-backed securities, 17 percent in cash and cash equivalents, 8 percent in small-cap U.S. companies and 11 percent in other investments.

(c) This category includes approximately 69 percent U.S. government-sponsored securities (asset-backed securities) and 31 percent U.S. government securities.

(d) This category includes approximately 78 percent corporate bonds and 22 percent municipal bonds.

(e) This category includes collateral held at December 31, 2009, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, money market funds, corporate bonds, commercial paper, asset-backed securities and certificates of deposit.

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2009:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Collateral Held on Loaned Securities
(In thousands)	
Balance at beginning of year	$ 573
Total realized/unrealized losses	80
Purchases, issuances and settlements (net)	284
Balance at end of year	$ 937

The fair value of the Company's other postretirement benefit plan assets by asset category is as follows:

	Fair Value Measurements at December 31, 2009, 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, 2009
	(In thousands)			
Assets:				
Money market funds	$1,469	$—	$ —	$1,469
Common stock	2,897	—	—	2,897
Insurance investment contract*	—	62,618	—	62,618
Total assets measured at fair value	$4,366	$62,618	$ —	$66,984

* Invested in mutual funds.

The Company expects to contribute approximately $10.2 million to its defined benefit pension plans and approximately $4.1 million to its postretirement benefit plans in 2010.

The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

Years	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2010	$20,431	$ 6,027
2011	20,744	6,244
2012	21,496	6,431
2013	22,151	6,686
2014	22,640	6,905
2015 - 2019	122,347	37,504

The following Medicare Part D subsidies are expected: $637,000 in 2010; $675,000 in 2011; $725,000 in 2012; $765,000 in 2013; $807,000 in 2014; and $4.7 million during the years 2015 through 2019.

In addition to company-sponsored plans, certain employees are covered under multi-employer pension plans administered by a union. Amounts contributed in 2009 to defined benefit and defined contribution multi-employer plans were $32.5 million and $16.4 million, respectively. Amounts contributed to the multi-employer plans were $73.1 million and $51.5 million in 2008 and 2007, respectively.

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 had investments of $67.9 million at December 31, 2009, consisting of equity securities of $32.1 million, life insurance carried on plan participants (payable upon the employee's death) of $29.8 million, fixed-income securities of $2.7 million and other investments of $3.3 million, which the Company anticipates using to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $8.8 million, $9.0 million and $7.6 million in 2009, 2008 and 2007, respectively. The total projected benefit obligation for these plans was $93.0 million and $87.2 million at December 31, 2009 and 2008, respectively. The accumulated benefit obligation for these plans was $84.8 million and $77.3 million at December 31, 2009 and 2008, respectively. A discount rate of 5.75 percent and 6.25 percent at December 31, 2009 and 2008, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2009 and 2008, were used to determine benefit obligations. A discount rate of 6.25 percent and 6.00 percent at December 31, 2009 and 2008, respectively, and a rate of compensation increase of 4.00 percent and 4.25 percent at December 31, 2009 and 2008, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans, as appropriate, are expected to aggregate $4.6 million in 2010; $5.0 million in 2011; $5.3 million in 2012; $5.9 million in 2013; $5.9 million in 2014; and $36.3 million for the years 2015 through 2019.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $20.5 million in 2009, $23.8 million in 2008 and $21.1 million in 2007.

Note 17 – Jointly Owned Facilities
The consolidated financial statements include the Company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the Big Stone Station and Coyote Station operating expenses was reflected in the appropriate categories of operating expenses 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:

	2009	2008
	(In thousands)	
Big Stone Station:		
Utility plant in service	$60,220	$61,030
Less accumulated depreciation	39,940	39,473
	$20,280	$21,557
Coyote Station:		
Utility plant in service	$131,042	$127,151
Less accumulated depreciation	82,402	82,018
	$48,640	$45,133

In April 2009, the Company purchased a 25 MW ownership interest in the Wygen III electric generation facility, which is under construction near Gillette, Wyoming, and is expected to be online in the second quarter of 2010. The Company's balance of construction work in progress related to this facility that is included in property, plant and equipment on the Consolidated Balance Sheets at December 31, 2009, is $56.1 million.

Note 18 – Regulatory Matters and Revenues Subject to Refund
In November 2006, Montana-Dakota filed an application with the NDPSC requesting an advance determination of prudence of Montana-Dakota's ownership interest in Big Stone Station II. In August 2008, the NDPSC approved Montana-Dakota's request for advance determination of prudence for ownership in the proposed Big Stone Station II for a minimum of 121.8 MW up to a maximum of 133 MW and a proportionate ownership share of the associated transmission electric resources. The intervenors in the proceeding appealed the NDPSC order to the North Dakota District Court which affirmed the order of the NDPSC. The intervenors then appealed the North Dakota District Court order to the North Dakota Supreme Court. The Big Stone Station II participants subsequently decided not to proceed with the project and on December 2, 2009, Montana-Dakota filed an application with the NDPSC for a determination that Montana-Dakota's continued participation in the Big Stone Station II is no longer prudent. The parties have stipulated that the intervenors will move to dismiss their appeal to the North Dakota Supreme Court if the NDPSC grants Montana-Dakota's pending application for a determination that its participation in the Big Stone Station II is no longer prudent. On December 4, 17, and 23, 2009, Montana-Dakota filed an application with the NDPSC, SDPUC, and MTPSC, respectively, for authority to defer the costs incurred for securing new electric generation, primarily Big Stone Station II, until the next general rate case.

On August 14, 2009, Montana-Dakota filed an application with the WYPSC for an electric rate increase. Montana-Dakota requested a total increase of $6.2 million annually or approximately 31 percent above current rates. The rate increase request was necessitated by the Company's 25 MW ownership interest in the Wygen III power generation facility currently under construction near Gillette, Wyoming. The generation will replace a portion of the purchased power currently used to serve its Wyoming system. On January 14, 2010, Montana-Dakota filed a supplement to the application to reflect the inclusion of bonus tax depreciation on the Wygen III plant, reducing its request to a $5.1 million annual increase or approximately 25 percent above current rates. A hearing has been set for February 23, 2010.

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. There had been one remaining issue outstanding related to this rate change application regarding certain service restrictions. After various steps in this proceeding, including a Williston Basin Request for Rehearing, an appeal to the D.C. Appeals Court, and a remand to FERC, the FERC, on October 30, 2009, issued its Order on Remand in which it upheld its previous decision. No party requested rehearing of the order, which is now final, and no issue is outstanding in this application.

Note 19 – Commitments and Contingencies

Litigation

Coalbed Natural Gas Operations Fidelity's CBNG operations are and have been the subject of numerous lawsuits in Montana and Wyoming. The current cases involve the permitting and use of water produced in connection with Fidelity's CBNG development in the Powder River Basin. Some of these cases challenge the issuance of discharge permits by the Montana DEQ and approval of other water management tools by the MBOGC.

In April 2006, the Northern Cheyenne Tribe filed a complaint in Montana Twenty-Second Judicial District Court against the Montana DEQ seeking to set aside Fidelity's renewed direct discharge and treatment permits. The Northern Cheyenne Tribe claimed the Montana DEQ violated the Clean Water Act and the Montana Water Quality Act by failing to include in the permits conditions requiring application of the best practicable control technology currently available and by failing to impose a nondegradation policy like the one the BER adopted soon after the permit was issued. In addition, the Northern Cheyenne Tribe claimed that the actions of the Montana DEQ violated the Montana State Constitution's guarantee of a clean and healthful environment, that the Montana DEQ's related environmental assessment was invalid, that the Montana DEQ was required, but failed, to prepare an EIS and that the Montana DEQ failed to consider other alternatives to the issuance of the permits. Fidelity, the NPRC, and the TRWUA were granted leave to intervene in this proceeding. On January 12, 2009, the Montana Twenty-Second Judicial District Court decided the case in favor of Fidelity and the Montana DEQ in all respects, denying the motions of the Northern Cheyenne Tribe, TRWUA, and NPRC, and granting the cross-motions of the Montana DEQ and Fidelity in their entirety. As a result, Fidelity may continue to utilize its direct discharge and treatment permits. The NPRC, the TRWUA and the Northern Cheyenne Tribe appealed the decision to the Montana Supreme Court on March 9, 11, and 13, 2009, respectively.

Fidelity's discharge of water pursuant to its two permits is its primary means for managing CBNG-produced water. Fidelity believes that its discharge permits should, assuming normal operating conditions, allow Fidelity to continue its existing CBNG operations through the expiration of the permits in March 2011. If its permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

In October 2003, Tongue & Yellowstone Irrigation District, NPRC and MEIC filed a lawsuit in Montana First Judicial District Court challenging the MBOGC's ROD adopting the 2003 Final EIS which analyzed CBNG development in the State of Montana. Through the amendment of the plaintiffs' pleadings and as a result of discovery, the defendants have now determined that the primary legal issue before the Court is whether the ROD authorizes the "wasting" of ground water in violation of the Montana State Constitution and the public trust doctrine. Specifically, the plaintiffs contend that various water management tools, including Fidelity's direct discharge permits, allow for the waste of water. Should the Montana First Judicial District Court determine that Fidelity's direct discharge permits violate the Montana State Constitution, Fidelity's Montana CBNG operations could be significantly and adversely affected.

Fidelity will continue to vigorously defend its interests in all CBNG-related litigation in which it is involved. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could adversely impact Fidelity's existing CBNG operations and/or the future development of this resource in the affected regions.

Electric Operations In June 2008, the Sierra Club filed a complaint in the South Dakota Federal District Court against Montana-Dakota and the two other co-owners of the Big Stone Station. The complaint alleged certain violations of the PSD and NSPS provisions of the Clean Air Act and certain violation of the South Dakota SIP. The action further alleged that the Big Stone Station was modified and operated without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleged that these actions contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought declaratory and injunctive relief to bring the co-owners of the Big Stone Station into compliance with the Clean Air Act and the South Dakota SIP and to require them to remedy the alleged violations. The Sierra Club also sought unspecified civil penalties, including a beneficial mitigation project. The Company believes the claims are without merit and that Big Stone Station has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. On March 31, 2009, the District Court granted the motion of the co-owners to dismiss the complaint. The Sierra Club filed a motion requesting the District Court to reconsider its ruling on a portion of the order dismissing the complaint which was denied on July 22, 2009. On July 30, 2009, the Sierra Club appealed from the orders dismissing the case and denying the motion for reconsideration to the United States Court of Appeals for the Eighth Circuit. The United States has filed a brief as amicus curiae supporting the Sierra Club's position in the appeal and the State of South Dakota filed a brief as amicus curiae supporting the Big Stone Station owners' position in the appeal.

Construction Materials LTM is a third-party defendant in litigation pending in Oregon Circuit Court regarding the concrete floors in an industrial food processing facility located in Jackson County, Oregon. The complaint against the facility construction contractor alleges the concrete floors of the facility are defective and must be removed and replaced for suitable repair. Damages, including disruption of the food processing operations, have been estimated by the plaintiff to be in excess of $32 million. The construction contractor's answer and third-party complaint alleges the owner and third-party defendants, including LTM which supplied the concrete, are primarily responsible for any defects in the concrete surfaces. Discovery is currently being conducted by the parties. A trial date has not been set.

The Company also is involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that the outcomes with respect to these other legal proceedings will not have a material adverse effect upon the Company's financial position or results of operations.

Environmental matters

Portland Harbor Site In December 2000, MBI 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 MBI 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 MBI 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. MBI 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 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, MBI does not believe it is a Responsible Party. In addition, MBI 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. MBI 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 of March 2, 2009, LWG stated its intent to file suit against MBI and others to recover LWG's investigation costs to the extent MBI 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, MBI 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 soil and groundwater contamination at a site in Oregon and 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. An ecological risk assessment draft report was submitted to the Oregon DEQ in June 2009. The assessment showed no unacceptable risk to the aquatic ecological receptors present in the shoreline along the site and concluded that no further ecological investigation is necessary. The report is being reviewed by the Oregon DEQ. It is anticipated the Oregon DEQ will recommend a cleanup alternative for the site after it completes its review of the report. It is not known at this time what share of the cleanup costs will actually be borne by Cascade.

The second claim is for contamination at a site in Washington and 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. There is currently not enough information to estimate the potential liability to Cascade associated with this claim.

The third claim is also for contamination at a site in 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’s predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim.

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.

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, 2009, were $25.2 million in 2010, $20.3 million in 2011, $15.3 million in 2012, $12.6 million in 2013, $6.7 million in 2014 and $43.9 million thereafter. Rent expense was $43.4 million, $35.3 million and $35.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage and construction materials supply contracts. These commitments range from 1 to 51 years. The commitments under these contracts as of December 31, 2009, were $507.6 million in 2010, $288.3 million in 2011, $192.1 million in 2012, $105.7 million in 2013, $90.3 million in 2014 and $234.9 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2009, 2008 and 2007, were $723.1 million, approximately $1.0 billion (including the acquisition of Intermountain as discussed in Note 2) and $857.0 million (including the acquisition of Cascade as discussed in Note 2), respectively.

Guarantees

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses that Petrobras may incur from certain contingent liabilities specified in the purchase agreement. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging up to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

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 Power LLC, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation. On February 27, 2009, Centennial received a Notice and Demand from LPP under the guaranty 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. On December 4, 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand seeks compensatory damages of $146 million plus damages for increased operating, capital and construction costs related to a water treatment facility for the generating facility. LPP’s notice of demand for arbitration also demanded performance of the guarantee by Centennial. The Company believes the indemnification claims against Centennial are without merit and intends to vigorously defend against such claims.

In connection with the pending sale of the Brazilian Transmission Lines, as discussed in Note 4, Centennial has agreed to guarantee the performance of certain of the Company’s indirect wholly owned subsidiaries in three purchase and sale agreements. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations of the wholly owned subsidiary sellers 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.

In addition, WBI Holdings has guaranteed certain of Fidelity’s natural gas swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas swap and collar agreements as the amount of the obligation is dependent upon natural gas commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas swap and collar agreements at December 31, 2009, expire in 2010 and 2011; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. There were no amounts outstanding by Fidelity at December 31, 2009. 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, a conditional purchase agreement and certain other guarantees. At December 31, 2009, the fixed maximum amounts guaranteed under these agreements aggregated $234.4 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $65.3 million in 2010; $141.8 million in 2011; $16.7 million in 2012; $1.8 million in 2013; $200,000 in 2014; $1.0 million in 2018; $300,000 in 2019; $3.3 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 $570,000 and was reflected on the Consolidated Balance Sheet at

December 31, 2009. 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, materials obligations, natural gas transportation agreements and other agreements that guarantee the performance of other subsidiaries of the Company. At December 31, 2009, the fixed maximum amounts guaranteed under these letters of credit, aggregated $37.1 million, which are scheduled to expire in 2010. There were no amounts outstanding under the above letters of credit at December 31, 2009.

WBI Holdings has an outstanding guarantee to Williston Basin. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2009, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2011. 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 $870,000. Prairielands also had $650,000 outstanding under a guarantee with Fidelity that will expire when paid. The amounts outstanding under these guarantees were not reflected on the Consolidated Balance Sheet at December 31, 2009, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial and Knife River have issued guarantees to third parties related to the Company's 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 its obligation in relation to the purchase of certain maintenance items, materials or lease obligations, Centennial or Knife River would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items and materials were reflected on the Consolidated Balance Sheet at December 31, 2009.

In the normal course of business, Centennial has purchased 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, 2009, approximately $532 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Note 20 – Subsequent Events

The Company evaluated for events or transactions between the balance sheet date and February 17, 2010, the date of the issuance of the financial statements, that would require recognition or disclosure in the financial statements.

Supplementary Financial Information
Quarterly Data (Unaudited)
The following unaudited information shows selected items by quarter for the years 2009 and 2008:

	First Quarter*	Second Quarter	Third Quarter	Fourth Quarter **
	(In thousands, except per share amounts)			
2009				
Operating revenues	$1,094,005	$958,040	$1,107,927	$1,016,529
Operating expenses	1,634,924	857,975	947,654	889,045
Operating income (loss)	(540,919)	100,065	160,273	127,484
Net income (loss)	(343,803)	55,311	92,584	72,634
Earnings (loss) per common share:				
Basic	(1.87)	.30	.50	.39
Diluted	(1.87)	.30	.50	.38
Weighted average common shares outstanding:				
Basic	183,787	183,964	185,160	187,748
Diluted	183,787	184,398	185,425	188,373
2008				
Operating revenues	$1,121,907	$1,251,772	$1,333,834	$1,295,765
Operating expenses	994,335	1,053,281	1,130,537	1,313,088
Operating income (loss)	127,572	198,491	203,297	(17,323)
Net income (loss)	71,051	115,507	118,382	(11,267)
Earnings (loss) per common share:				
Basic	.39	.63	.65	(.06)
Diluted	.39	.63	.64	(.06)
Weighted average common shares outstanding:				
Basic	182,599	182,972	183,219	183,603
Diluted	183,130	183,727	184,081	183,603

* 2009 reflects a $384.4 million after-tax noncash write-down of natural gas and oil properties.
** 2008 reflects an $84.2 million after-tax noncash write-down of natural gas and oil properties.

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.

Natural Gas and Oil Activities (Unaudited)
Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties with potential development opportunities, exploratory drilling and the operation and development of production properties. Fidelity shares revenues and expenses from the development of specified properties in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico in proportion to its ownership interests.

Fidelity owns in fee or holds natural gas leases for the properties it operates in Colorado, Montana, North Dakota, Texas, Utah and Wyoming. These rights are in the Bonny Field in eastern Colorado, the Baker Field in southeastern Montana and southwestern North Dakota, the Bowdoin area in north-central Montana, the Powder River Basin of Montana and Wyoming, the Bakken area in North Dakota, the Paradox Basin of Utah, the Tabasco and Texan Gardens fields of Texas

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and the Big Horn Basin in Wyoming. In 2008, Fidelity acquired and became the operator of natural gas properties in Rusk County in eastern Texas.

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

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

	2009	2008	2007
		(In thousands)	
Subject to amortization	$1,815,380	$2,211,865	$1,750,233
Not subject to amortization	178,214	232,081	142,524
Total capitalized costs	1,993,594	2,443,946	1,892,757
Less accumulated depreciation, depletion and amortization	969,630	846,074	681,101
Net capitalized costs	$1,023,964	$1,597,872	$1,211,656

Note: Net capitalized costs as of December 31, 2009 and 2008, reflect noncash write-downs of the Company's natural gas and oil properties, as discussed in Note 1.

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

Years ended December 31,	2009 *	2008 *	2007 *
		(In thousands)	
Acquisitions:			
Proved properties	$3,879	$225,610	$426
Unproved properties	8,771	107,419	17,731
Exploration	33,123	109,828	48,744
Development* *	135,202	260,098	214,433
Total capital expenditures	$180,975	$702,955	$281,334

*Excludes net additions to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of natural gas and oil wells, as discussed in Note 10, of $2.0 million, $3.0 million and $5.4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

** Includes expenditures for proved undeveloped reserves of $32.5 million, $46.7 million and $74.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

Years ended December 31,	2009	2008	2007
		(In thousands)	
Revenues:			
Sales to affiliates	$101,230	$291,642	$226,706
Sales to external customers	338,425	420,488	287,557
Production costs	123,148	161,401	123,924
Depreciation, depletion and amortization*	126,278	167,427	124,599
Write-down of natural gas and oil properties	620,000	135,800	—
Pretax income	(429,771)	247,502	265,740
Income tax expense	(164,216)	91,593	98,729
Results of operations for producing activities	$(265,555)	$155,909	$167,011

* Includes accretion of discount for asset retirement obligations of $2.7 million, $2.5 million and $2.5 million for the years ended December 31, 2009, 2008 and 2007, respectively, as discussed in Note 10.

The following table summarizes the Company's estimated quantities of proved natural gas and oil reserves at December 31, 2009, 2008 and 2007, and reconciles the changes between these dates. 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. Other factors used in the reserve estimates are natural gas and oil prices, current 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 reserve estimates as of December 31, 2009, were calculated using SEC Defined Prices and prior to that time, reserve estimates were calculated using spot market prices that existed at the end of the applicable period. SEC Defined Prices used for the December 31, 2009, reserve estimates for natural gas were significantly lower than December 31, 2008, spot market prices. As a result, the Company had significant negative revisions of previous estimates to its reserves. Because SEC rules require proved reserves to be economically producible, the price used is inherent in that determination. If the rules regarding the prices used to calculate reserves had not been changed, the Company believes it would not have had significant negative revisions to its reserves due to pricing, as spot market prices on December 31, 2009, were higher than December 31, 2008, spot market prices.

The reserve estimates are prepared by internal engineers assigned to an asset team by geographic area and are reviewed and approved by management. In addition, the Company engages an independent third party to audit its proved reserves. Ryder Scott Company, L.P. reviewed the Company’s proved reserve quantity estimates as of December 31, 2009.

Estimates of economically recoverable natural gas and oil 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.

	2009		2008		2007	
	Natural Gas	Oil	Natural Gas	Oil	Natural Gas	Oil
			(MMcf/MBbls)			
Proved developed and undeveloped reserves:						
Balance at beginning of year	604,282	34,348	523,737	30,612	538,100	27,100
Production	(56,632)	(3,111)	(65,457)	(2,808)	(62,798)	(2,365)
Extensions and discoveries	26,882	2,569	78,338	4,941	77,701	3,772
Improved recovery	—	—	—	—	444	1,614
Purchases of proved reserves	—	—	92,564	834	2	6
Sales of reserves in place	(22)	(248)	—	—	(6)	(42)
Revisions of previous estimates	(126,085)	658	(24,900)	769	(29,706)	527
Balance at end of year	448,425	34,216	604,282	34,348	523,737	30,612
Proved reserves:						
Developed	321,561	26,794	431,180	26,862	420,137	25,658
Undeveloped	126,864	7,422	173,102	7,486	103,600	4,954
Balance at end of year	448,425	34,216	604,282	34,348	523,737	30,612

The level of proved undeveloped reserves converted to developed in 2009 was less than anticipated as the Company’s drilling plans were modified due to the lower price environment experienced in 2009 and the Company’s focus to preserve capital. The Company did not have any material proved undeveloped locations that remained undeveloped for five years or more as of December 31, 2009.

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

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

	2009	2008	2007
		(In thousands)	
Future cash inflows	$2,991,200	$3,970,000	$5,302,300
Future production costs	1,095,600	1,325,600	1,415,700
Future development costs	315,000	377,300	237,600
Future net cash flows before income taxes	1,580,600	2,267,100	3,649,000
Future income tax expense	291,000	501,200	1,179,900
Future net cash flows	1,289,600	1,765,900	2,469,100
10% annual discount for estimated timing of cash flows	630,800	796,100	1,107,200
Discounted future net cash flows relating to proved natural gas and oil reserves	$658,800	$969,800	$1,361,900

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

	2009	2008	2007
		(In thousands)	
Beginning of year	$969,800	$1,361,900	$1,003,500
Net revenues from production	(200,900)	(547,000)	(354,100)
Change in net realization	(364,800)	(687,100)	527,900
Extensions and discoveries, net of future production-related costs	70,500	209,600	310,300
Improved recovery, net of future production-related costs	—	—	38,100
Purchases of proved reserves, net of future production-related costs	—	138,100	200
Sales of reserves in place	(1,100)	—	(1,300)
Changes in estimated future development costs	43,600	11,000	(22,600)
Development costs incurred during the current year	46,400	66,300	103,000
Accretion of discount	115,900	183,800	133,700
Net change in income taxes	142,800	372,300	(212,500)
Revisions of previous estimates	(155,500)	(132,200)	(163,700)
Other	(7,900)	(6,900)	(600)
Net change	(311,000)	(392,100)	358,400
End of year	$658,800	$969,800	$1,361,900

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using prices as previously discussed. Future development and production costs attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future development costs estimated to be spent in each of the next three years to develop proved undeveloped reserves as of December 31, 2009, are $88.9 million in 2010, $69.1 million in 2011 and $41.8 million in 2012. Future income tax expenses were computed by applying statutory tax rates, adjusted for permanent differences and tax credits, to estimated net future pretax cash flows.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of natural gas and oil 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 natural gas and oil 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) of the Exchange Act. The Company's 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 chief executive officer and chief financial officer have evaluated the effectiveness of the Company's disclosure controls and procedures and they 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
The Company maintains a system of internal accounting controls that is designed to provide reasonable assurance that the Company's transactions are properly authorized, the Company's assets are safeguarded against unauthorized or improper use, and the Company's transactions are properly recorded and reported to permit preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America. There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended December 31, 2009, that have materially affected, or are 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 fourth 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, 2009, 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)	1,087,973	(2)	$ 19.80	7,262,380	(3)(4)
Equity compensation plans not approved by stockholders (5)	371,403		13.22	2,361,073	(6)
Total	1,459,376		$ 18.13	9,623,453	

(1) Consists of the 1992 Key Employee Stock Option Plan, 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) Includes 634,505 performance shares.
(3) In addition to being available for future issuance upon exercise of options, 357,757 shares under the Non-Employee Director Long-Term Incentive Compensation Plan may instead be issued in connection with stock appreciation rights, restricted stock, performance units, performance shares or other equity-based awards, and 5,861,739 shares under the Long-Term Performance-Based Incentive Plan may instead be issued in connection with stock appreciation rights, restricted stock, performance units, performance shares or other equity-based awards.
(4) This amount also includes 364,628 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, nonemployee Directors are awarded 4,050 shares following the Company's annual meeting of stockholders. Prior to January 1, 2009, the Company's Chairman of the Board of Directors received an additional $50,000 in stock under the plan each December as part of his retainer. 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.
(5) Consists of the 1998 Option Award Program and the Group Genius Innovation Plan.
(6) In addition to being available for future issuance upon exercise of options, 219,050 shares under the Group Genius Innovation Plan may instead be issued in connection with stock appreciation rights, restricted stock, restricted stock units, performance units, performance stock or other equity-based awards.

The following equity compensation plans have not been approved by the Company's stockholders.

The 1998 Option Award Program

The 1998 Option Award Program is a broad-based plan adopted by the Board of Directors, effective February 12, 1998. The plan permits the grant of nonqualified stock options to employees of the Company and its subsidiaries. The maximum number of shares that may be issued under the plan is 3,795,330. Shares granted may be authorized but unissued shares, treasury

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shares, or shares purchased on the open market. Option exercise prices are equal to the market value of the Company's shares on the date of the option grant. Optionees receive dividend equivalents on their options, with any credited dividends paid in cash to the optionee if the option vests, or forfeited if the option is forfeited. Vested options remain exercisable for one year following termination of employment due to death or disability and for three months following termination of employment for any other reason.

Unvested options are forfeited upon termination of employment. Subject to the terms and conditions of the plan, the plan's administrative committee determines the number of shares subject to options granted to each participant and the other terms and conditions pertaining to such options, including vesting provisions. All options become immediately exercisable in the event of a change in control of the Company.

In 2001, 450 options (adjusted for the three-for-two stock splits in October 2003 and July 2006) were granted to each of approximately 5,900 employees. No officers received grants. These options vested on February 13, 2004. As of December 31, 2009, options covering 371,403 shares of common stock were outstanding under the plan and 2,142,023 shares remained available for future grant. Options covering 1,281,904 shares had been exercised.

The Group Genius Innovation Plan

The Group Genius Innovation Plan was adopted by the Board of Directors, effective May 17, 2001, to encourage employees to share ideas for new business directions for the Company and to reward them when the idea becomes profitable. Employees of the Company and its subsidiaries who are selected by the plan's administrative committee are eligible to participate in the plan. Officers and Directors are not eligible to participate. The plan permits the granting of nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance stock and other awards. The maximum number of shares that may be issued under the plan is 223,150. Shares granted under the plan may be authorized but unissued shares, treasury shares or shares purchased on the open market. Restricted stockholders have voting rights and, unless determined otherwise by the plan's administrative committee, receive dividends paid on the restricted stock. Dividend equivalents payable in cash may be granted with respect to options and performance shares. The plan's administrative committee determines the number of shares or units subject to awards, and the other terms and conditions of the awards, including vesting provisions and the effect of employment termination. Upon a change in control of the Company, all options and stock appreciation rights become immediately vested and exercisable, all restricted stock becomes immediately vested, all restricted stock units become immediately vested and are paid out in cash, and target payout opportunities under all performance units, performance stock, and other awards are deemed to be fully earned, with awards denominated in stock paid out in shares and awards denominated in units paid out in cash. As of December 31, 2009, 4,100 shares of stock had been granted to 73 employees.

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.

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.

2. Financial Statement Schedules

MDU Resources Group, Inc.
Schedule II - Consolidated Valuation and Qualifying Accounts
Years Ended December 31, 2009, 2008 and 2007

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:					
2009	$13,691	$12,152	$1,412	$10,606	$16,649
2008	14,635	12,191	2,115	15,250	13,691
2007	7,725	8,799	5,533	7,422	14,635

*Allowance for doubtful accounts for companies acquired and 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 17, 2007, filed as Exhibit 3.1 to Form 8-A/A, filed on June 27, 2007, in File No. 1-3480*

3(b)Company Bylaws, as amended and restated, on November 12, 2009**

4(a)Indenture of Mortgage, dated as of May 1, 1939, as restated in the Forty-Fifth Supplemental Indenture, dated as of April 21, 1992, and the Forty-Sixth through Fiftieth Supplements thereto between the Company and the New York Trust Company (The Bank of New York, successor Corporate Trustee) and A. C. Downing (Douglas J. MacInnes, successor Co-Trustee), filed as Exhibit 4(a) to Form S-3, in Registration No. 33-66682; and Exhibits 4(e), 4(f) and 4(g) to Form S-8, in Registration No. 33-53896; and Exhibit 4(c)(i) to Form S-3, in Registration No. 333-49472; and Exhibit 4(e) to Form S-8, in Registration No. 333-112035*

4(b)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(c)First Supplemental Indenture, dated as of November 17, 2009, between the Company and The Bank of New York Mellon, as trustee**

4(d)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(e)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(f)MDU Resources Group, Inc. Credit Agreement, dated June 21, 2005, among MDU Resources Group, Inc., Wells Fargo Bank, National Association, as Administrative Agent, and The Other Financial Institutions Party thereto, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

4(g)First Amendment, dated June 30, 2006, to Credit Agreement, dated June 21, 2005, among MDU Resources Group, Inc., Wells Fargo Bank, National Association, as administrative agent, and certain lenders described in the credit agreement, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(h)Centennial Energy Holdings, Inc. Credit Agreement, dated December 13, 2007, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto, filed as Exhibit 4(j) to Form 10-K for the year ended December 31, 2007, filed on February 20, 2008, in File No. 1-3480*

4(i)Consent dated November 9, 2009, under Centennial Energy Holdings, Inc. Credit Agreement, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto**

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

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

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

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

4(o)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*

+10(a)1992 Key Employee Stock Option Plan, as revised, filed as Exhibit 10(a) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(b)Supplemental Income Security Plan, as amended and restated November 12, 2009**

+10(c)Directors' Compensation Policy, as amended May 14, 2009, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2009, filed on August 7, 2009, in File No. 1-3480*

+10(d)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(e)Non-Employee Director Stock Compensation Plan, as amended May 15, 2008, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2008, filed on August 7, 2008, in File No. 1-3480*

+10(f)Non-Employee Director Long-Term Incentive Compensation Plan, as amended November 12, 2009**

+10(g)1998 Option Award Program, as amended November 12, 2009**

+10(h)Group Genius Innovation Plan, as amended November 12, 2009**

+10(i)WBI Holdings, Inc. Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended November 11, 2009**

+10(j)Knife River Corporation Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended November 16, 2009**

+10(k)Long-Term Performance-Based Incentive Plan, as amended November 12, 2009**

+10(l)MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended November 15, 2007, and Rules and Regulations, as amended November 11, 2009**

+10(m)Montana-Dakota Utilities Co. Executive Incentive Compensation Plan, as amended November 15, 2007, and Rules and Regulations, as amended November 11, 2009**

+10(n)Form of Change of Control Employment Agreement, as amended May 15, 2008, filed as Exhibit 10.1 to Form 8-K dated May 15, 2008, filed on May 20, 2008, in File No. 1-3480*

+10(o)MDU Resources Group, Inc. Executive Officers with Change of Control Employment Agreements Chart, as of December 31, 2008, filed as Exhibit 10(p) to Form 10-K for the year ended December 31, 2008, filed on February 13, 2009, in File No. 1-3480*

+10(p)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(q)Employment Letter for John G. Harp, dated July 20, 2005, filed as Exhibit 10(ah) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(r)Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended August 13, 2008, filed as

Exhibit 10.1 to Form 8-K dated August 13, 2008, filed on August 19, 2008, in File No. 1-3480*

+10(s) MDU Construction Services Group, Inc. Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended February 16, 2009, filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2009, filed on May 6, 2009, in File No. 1-3480*

+10(t) John G. Harp 2009 additional incentive opportunity, filed as Exhibit 10(f) to Form 10-Q for the quarter ended March 31, 2009, filed on May 6, 2009, in File No. 1-3480*

+10(u) Form of 2009 Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, filed as Exhibit 10(g) to Form 10-Q for the quarter ended March 31, 2009, filed on May 6, 2009, in File No. 1-3480*

+10(v) MDU Resources Group, Inc. 401(k) Retirement Plan, as restated June 1, 2009, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2009, filed on August 7, 2009, in File No. 1-3480*

+10(w) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 2, 2009**

+10(x) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 30, 2009**

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**

99(a) Sales Agency Financing Agreement entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 1 to Form 8-K dated September 5, 2008, filed on September 5, 2008, in File No. 1-3480*

99(b) Ryder Scott Company, L.P. report dated January 22, 2010 **

101 The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2009, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Common Stockholders' Equity, (iv) the Consolidated Statements of Cash Flows, (v) the Notes to Consolidated Financial Statements, tagged as blocks of text and (vi) Schedule II – Consolidated Valuation and Qualifying Accounts, tagged as a block of text

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* 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 17, 2010 By: /s/ Terry D. Hildestad
Terry D. Hildestad
(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/ Terry D. Hildestad Terry D. Hildestad (President and Chief Executive Officer)	Chief Executive Officer and Director	February 17, 2010
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 17, 2010
/s/ Nicole A. Kivisto Nicole A. Kivisto (Vice President, Controller and Chief Accounting Officer)	Chief Accounting Officer	February 17, 2010
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 17, 2010
/s/ Thomas Everist Thomas Everist	Director	February 17, 2010
/s/ Karen B. Fagg Karen B. Fagg	Director	February 17, 2010
/s/ A. Bart Holaday A. Bart Holaday	Director	February 17, 2010
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 17, 2010
/s/ Thomas C. Knudson	Director	February 17, 2010

Thomas C. Knudson		
/s/ Richard H. Lewis Richard H. Lewis	Director	February 17, 2010
/s/ Patricia L. Moss Patricia L. Moss	Director	February 17, 2010
/s/ Sister Thomas Welder Sister Thomas Welder	Director	February 17, 2010
/s/ John K. Wilson John K. Wilson	Director	February 17, 2010