SECURITIES AND EXCHANGE COMMISSION

FORM 10-K

Annual report pursuant to section 13 and 15(d)

Filing Date: **2012-02-24** | Period of Report: **2011-12-31**
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FILER

MDU RESOURCES GROUP INC	Mailing Address	Business Address
CIK:**67716**| IRS No.: **410423660** | State of Incorp.:**DE** | Fiscal Year End: **1231** Type: **10-K** | Act: **34** | File No.: **001-03480** | Film No.: **12636108** SIC: **1400** Mining & quarrying of nonmetallic minerals (no fuels)	*1200 WEST CENTURY AVENUE* *BISMARCK ND 58503*	*1200 WEST CENTURY AVENUE* *BISMARCK ND 58503* *701-530-1059*

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

FORM 10-K

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

For the fiscal year ended December 31, 2011

OR

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

For the transition period from ____________ to _____________

Commission file number 1-3480

MDU Resources Group, Inc.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

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

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

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

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐

(Do not check if a smaller reporting company)

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

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2011: $4,247,855,190.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 17, 2012:
188,819,307 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2012 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

Part I

Part II

Part III

Part IV

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
Alusa	Tecnica de Engenharia Electrica - Alusa
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Bicent	Bicent Power LLC
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
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 the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and a portion of the ownership interest in ECTE was sold in the fourth quarter of 2011 and 2010)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
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 Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (7.51 percent ownership interest at December 31, 2011, 2.5 and 14.99 percent ownership interest was sold in 2011 and 2010, respectively)
EIN	Employer Identification Number
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974

ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)

ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River (previously Morse Bros., Inc., name changed effective January 1, 2010)
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LTM	LTM, Inc., an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MAPP	Mid-Continent Area Power Pool
MBbls	Thousands of barrels
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand decatherms
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
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 Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County

Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
Oil	Includes crude oil, condensate and natural gas liquids
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon Circuit Court	Circuit Court of the State of Oregon for the County of Klamath
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PDP	Proved developed producing
PRC	Planning resource credit - a MW of demand equivalent assigned to generators by the Midwest ISO for meeting system reliability requirements
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2012 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
Ryder Scott	Ryder Scott Company, L.P.
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of 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
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
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
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
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 services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (comprised of the pipeline and energy services and the exploration and production segments), Knife River (construction materials and contracting segment), MDU Construction Services (construction services segment), Centennial Resources and Centennial Capital (both reflected in the Other category).

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

As of December 31, 2011, the Company had 8,021 employees with 150 employed at MDU Resources Group, Inc., 960 at Montana-Dakota, 31 at Great Plains, 277 at Cascade, 216 at Intermountain, 625 at WBI Holdings, 2,786 at Knife River and 2,976 at MDU Construction Services. The number of employees at certain Company operations fluctuates during the year depending upon the number and size of construction projects. The Company considers its relations with employees to be satisfactory.

The following information regarding the number of employees represented by labor contracts is as of December 31, 2011.

At Montana-Dakota and Williston Basin, 362 and 87 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2015, and March 31, 2014, for Montana-Dakota and Williston Basin, respectively.

At Cascade, 169 employees are represented by the ICWU. The labor contract with the field operations group is effective through April 1, 2012.

At Intermountain, 111 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2013.

Knife River has 43 labor contracts that represent approximately 520 of its construction materials employees. Knife River is in negotiations on 10 of its labor contracts.

MDU Construction Services has 144 labor contracts representing the majority of its employees. The majority of the labor contracts contain provisions that prohibit work stoppages or strikes and provide for binding arbitration dispute resolution in the event of an extended disagreement.

The Company's principal properties, which are of varying ages and are of different construction types, are generally in good condition, are well maintained and are generally suitable and adequate for the purposes for which they are used.

The financial results and data applicable to each of the Company's business segments, as well as their financing requirements, are set forth in Item 7 - MD&A and Item 8 - Note 15 and Supplementary Financial Information.

The operations of the Company and certain of its subsidiaries are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. The Company believes that it is in substantial compliance with these regulations, except as to what may be ultimately determined with regard to items discussed in Environmental matters in Item 8 - Note 19. There are no pending CERCLA actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site and one of the manufactured gas plant sites in Washington.

The Company produces GHG emissions primarily from its fossil fuel electric generating facilities, as well as from natural gas pipeline and storage systems, operations of equipment and fleet vehicles, and oil and natural gas exploration and development activities. GHG emissions also result from customer use of natural gas for heating and other uses. As interest in reductions in GHG emissions has grown, the Company has developed renewable generation with lower or no GHG emissions. Governmental legislative and regulatory initiatives regarding environmental and energy policy are continuously evolving and could negatively impact the Company's operations and financial results. Until legislation and regulation are finalized, the impact of these measures cannot be accurately predicted. The Company will continue to monitor legislative and regulatory activity related to environmental and energy policy initiatives. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description later. In addition, for a discussion of the Company's risks related to environmental laws and regulations, see Item 1A - Risk Factors.

This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q, 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 127,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2011. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 11 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. At December 31, 2011, Montana-Dakota's net electric plant investment was $604.7 million.

The percentage of Montana-Dakota's 2011 retail electric utility operating revenues by jurisdiction is as follows: North Dakota - 61 percent; Montana - 23 percent; Wyoming - 10 percent; and South Dakota - 6 percent. Retail electric rates, service, accounting and certain security issuances are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC. The

interstate transmission and wholesale electric power operations of Montana-Dakota also are subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of securities, accounting and other matters.

Through the Midwest ISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets. 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, ancillary services and capacity markets. 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, Mandan, Dickinson and Williston; eastern Montana, including Glendive and Miles City; and northern South Dakota, including Mobridge. The maximum electric peak demand experienced to date attributable to Montana-Dakota's sales to retail customers on the interconnected system was 535,761 kW in July 2011. 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 2017 will approximate 1 percent to 2 percent annually. The interconnected system consists of 10 electric generating facilities, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 493,055 kW and total net PRCs of 433.6 in 2011. PRCs are a MW of demand equivalent measure and are allocated to individual generators to meet supply obligations within the Midwest ISO. For 2011, Montana-Dakota's total PRCs, including its firm purchase power contracts, were 572.8. Montana-Dakota's peak demand supply obligation, including firm purchase power contracts, within the Midwest ISO was 524.2 PRCs for 2011. 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, two wind electric generating facilities and a heat recovery electric generating facility supply the balance of Montana-Dakota's interconnected system electric generating capability.

Montana-Dakota has a contract for capacity of 110 MW for the period June 1, 2012 to May 31, 2013, 115 MW for the period June 1, 2013 to May 31, 2014 and 120 MW for the period June 1, 2014 to May 31, 2015. Energy also will be purchased as needed, or if more economical, from the Midwest ISO market. In 2011, Montana-Dakota purchased approximately 21 percent of its net kWh needs for its interconnected system through the Midwest ISO market.

Montana-Dakota filed for an advance determination of prudence on July 7, 2011, with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities. The capacity would be a partial replacement for the contract expiring in 2015. For additional information, see Item 8 - Note 18.

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 49,000 kW of capacity annually through December 31, 2016. Wygen III, which commenced commercial operation in the second quarter of 2010, serves a portion of the needs of its Sheridan-area customers.

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

Generating Station	Type	Nameplate Rating (kW)	Summer Capability (kW) (a)	2011 PRCs (a)	2011 Net Generation (kWh in thousands)
Interconnected System:					
North Dakota:					
Coyote (b)	Steam	103,647	104,900	96.2	755,779
Heskett	Steam	86,000	104,300	85.6	500,080
Williston	Combustion Turbine	7,800	—	—	(68) (c)
Glen Ullin	Heat Recovery	7,500	—	—	43,133
Cedar Hills	Wind	19,500	19,500	3.9	59,468
South Dakota:					
Big Stone (b)	Steam	94,111	108,600	103.3	508,058
Montana:					
Lewis & Clark	Steam	44,000	53,100	52.1	300,782
Glendive	Combustion Turbine	77,347	74,900	66.1	15,431
Miles City	Combustion Turbine	23,150	23,600	20.0	218
Diamond Willow	Wind	30,000	30,000	6.4	98,867
		493,055	518,900	433.6	2,281,748
Sheridan System:					
Wyoming:					
Wygen III (b)	Steam	28,000	N/A	N/A	206,589
		521,055	518,900	433.6	2,488,337

(a) Interconnected system only. The summer capability values were used previously by MAPP for determining available generation for resource adequacy. The Midwest ISO requires generators to obtain their summer capability, or PRCs, by applying the generator's forced outage factor against the results of a generator output verification test. Wind generator's PRCs are calculated based on a wind capacity study performed annually by the Midwest ISO. PRCs are used to meet supply obligations with the Midwest ISO.

(b) Reflects Montana-Dakota's ownership interest.

(c) Station use, to meet Midwest ISO's requirements, exceeded generation.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland under contracts that expire in May 2016, April 2016 and December 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 Lewis & Clark and existing Heskett coal supply agreements provide for the purchase of coal necessary to supply the coal requirements of these stations at contracted pricing. Montana-Dakota estimates the Heskett and Lewis & Clark coal requirement to be in the range of 450,000 to 550,000 tons and 250,000 to 350,000 tons per contract year, respectively.

Montana-Dakota has a coal supply agreement, which meets the majority of the Big Stone Station's fuel requirements, for the purchase of 1.5 million tons of coal in 2012 with Peabody Coalsales, LLC at contracted pricing.

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

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

Years ended December 31,		**2011**		2010		2009
Average cost of coal per MMBtu	**$**	**1.62**	$	1.55	$	1.52
Average cost of coal per ton	**$**	**23.38**	$	22.60	$	22.05

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 purchase contracts or the Midwest ISO capacity auction. For additional information regarding potential power generation projects, see Item 7 - MD&A - Prospective Information - Electric and natural gas distribution.

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

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

Regulatory Matters and Revenues Subject to Refund In North Dakota, Montana-Dakota reflects monthly increases or decreases in fuel and purchased power costs (including demand charges) and is deferring electric fuel and purchased power costs that are greater or less than amounts presently being recovered through its existing rate schedules. In Montana, a monthly Fuel and Purchased Power Tracking Adjustment mechanism allows Montana-Dakota to reflect 90 percent of the increases or decreases in fuel and purchased power costs (including demand charges) and Montana-Dakota is deferring 90 percent of costs that are greater or less than amounts presently being recovered through its existing rate schedules. A fuel adjustment clause contained in South Dakota jurisdictional electric rate schedules allows Montana-Dakota to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota to reflect increases or decreases in purchased power costs (including demand charges) 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.

For information on regulatory matters, 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 Glendive and Miles City combustion turbine facilities were renewed in 2011.

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

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

Montana-Dakota incurred $3.6 million of environmental capital expenditures in 2011. Capital expenditures are estimated to be $15.3 million, $47.8 million and $90.0 million in 2012, 2013 and 2014, respectively, to maintain environmental compliance as new emission controls are required, including the installation of a BART air quality control system at the Big Stone Station. Additional expenditures for this BART project are expected during 2015 and 2016 of approximately $40.0 million. Projects for 2012 through 2014 will also include sulfur-dioxide, nitrogen oxide and mercury and non-mercury metals control equipment installation at electric generating stations. Montana-Dakota's capital and operational expenditures could also be affected in a variety of ways by 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 846,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states as of December 31, 2011, and provide natural gas transportation services to certain customers on their systems. These services are provided through distribution systems aggregating approximately 18,000 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. At December 31, 2011, the natural gas distribution operations' net natural gas distribution plant investment was $986.0 million.

The percentage of the natural gas distribution operations' 2011 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho - 33 percent; Washington - 26 percent; North Dakota - 12 percent; Oregon - 9 percent; Montana - 8 percent; South Dakota - 6 percent; Minnesota - 4 percent; and Wyoming - 2 percent. The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of Idaho, including Boise, Nampa, Twin Falls, Pocatello and Idaho Falls; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; North Dakota, including Bismarck, Mandan, Dickinson, Wahpeton, Williston, 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, 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 various regional transmission pipelines, including the systems of Williston Basin and Northwest Pipeline GP. 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 with several major transporters, including Williston Basin and Northwest Pipeline GP. The natural gas distribution operations have contracts for storage services to provide gas supply during the winter heating season and to meet peak day demand with various storage providers, including Williston Basin, Questar Pipeline Company and Northwest Pipeline GP. In addition, certain of the operations have entered into natural gas supply management agreements with various parties. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements as well as changes in market price. The natural gas distribution operations believe that, based on current and projected domestic and regional supplies of natural gas and the pipeline transmission network currently available through their suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next decade.

Regulatory Matters The natural gas distribution operations' retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under- or over-recovered gas costs within a period ranging from 12 to 28 months.

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

Cascade has received approval for decoupling its margins from weather and conservation in Oregon. This mechanism is expected to expire in the third quarter of 2012. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

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

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

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

In 2011 and 2010, the natural gas distribution operations reserved $1.2 million and $6.4 million for remediation of former manufactured gas plants in Oregon and Washington, respectively. The natural gas distribution operations did not incur any other material environmental expenditures in 2011. Except as to what may be ultimately determined with regard to the issues described later, the natural gas distribution operations do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2014.

Montana-Dakota has had an economic interest in four historic manufactured gas plants and Great Plains has had an economic interest in one historic manufactured gas plant within their service territories, 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 in the investigation and remediation of manufactured gas plants in Washington and Oregon, as previously discussed. In addition, Cascade received a third party claim notice in 2008 for one additional site in Washington. See Item 8 - Note 19 for a further discussion of these three manufactured gas plants. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Pipeline and Energy Services

General 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 12 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, 2011, Williston Basin's net plant investment was $315.4 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 of WBI Holdings, owns and operates gathering facilities in Colorado, Kansas, Montana and Wyoming. In total, these facilities include over 1,900 miles of field gathering lines and 86 owned or leased compression stations, some of which interconnect with Williston Basin's system. Bitter Creek also provides a variety of energy-related services such as cathodic protection, water hauling, contract compression operations, measurement services and energy efficiency product sales and installation services to large end-users.

Prairielands, the energy services business of WBI Holdings, 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 exploration and production segment. Certain of the services are provided based on contracts that call for a determinable quantity of natural gas. At December 31, 2011, Prairielands has commitments to deliver fixed and determinable amounts of natural gas under these contracts of 9.2 Bcf in 2012 and the commitments to deliver natural gas for years subsequent to 2012 are immaterial. WBI Holdings currently estimates that it can adequately meet the requirements of these contracts based upon its estimated natural gas production and reserves. 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.

For information regarding natural gas gathering operations litigation, see Item 8 - Note 19.

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, 2011, represented 52 percent of Williston Basin's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2017. In addition, Montana-Dakota has a contract with 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. 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 has 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 also provides a nontraditional natural gas supply to the Williston Basin system. 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.

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 2011 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2014.

Exploration and 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 Rocky Mountain region includes the following significant operating areas:

- Bakken areas - Fidelity significantly increased its acreage position in the Bakken oil play in 2011. The Company holds approximately 16,000 net acres in Mountrail County, North Dakota, approximately 50,000 net acres in Stark County, North Dakota, and approximately 30,000 net acres in Richland County, Montana.
- Cedar Creek Anticline - Primarily in eastern Montana, the Company has a long-held net profits interest in this oil play.
- Other exploratory oil projects - Fidelity holds approximately 75,000 net acres in the Paradox Basin in Utah, approximately 65,000 net acres in the Niobrara play in Wyoming and approximately 90,000 net acres in the Heath Shale prospect in Montana.
- Big Horn Basin - These interests include approximately 36,000 net acres and are in Wyoming, targeting oil and natural gas liquids.
- Green River Basin - These properties are primarily natural gas targets in Wyoming in which the Company holds approximately 36,000 net acres.
- Baker Field - Long-held natural gas properties in which Fidelity holds approximately 98,000 net acres in southeastern Montana and southwestern North Dakota.
- Bowdoin Field - Long-held natural gas properties in which Fidelity holds approximately 127,000 net acres in north-central Montana.
- Other - Includes the Powder River Basin and Bonny Field which Fidelity anticipates divesting of in 2012, along with various non-operated positions.

Mid-Continent/Gulf States

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

- South Texas - This area includes approximately 10,000 net acres in the Tabasco, Texan Gardens and Flores fields. This area has significant natural gas liquids content associated with the natural gas.
- East/Central Texas - Fidelity holds approximately 28,000 net acres.
- Other - Includes various non-operated onshore interests, as well as offshore interests in the shallow waters off the coasts of Texas and Louisiana.

Operating Information Annual net production by region for 2011 was as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total
Rocky Mountain	34,472	2,489	49,407	74%
Mid-Continent/Gulf States	11,126	1,011	17,189	26
Total	45,598	3,500	66,596	100%

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

Annual net production by region for 2010 was as follows:

Region	Natural Gas (MMcf) *	Oil (MBbls)	Total (MMcfe)	Percent of Total
Rocky Mountain	39,160	2,365	53,350	76%
Mid-Continent/Gulf States	11,231	897	16,613	24
Total	50,391	3,262	69,963	100%

* Baker field and Bowdoin field represent 28 percent and 20 percent, respectively, of total annual net natural gas production, and are the only fields that contain 15 percent or more of the Company's total proved reserves.

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, and are the only fields that contain 15 percent or more of the Company's total proved reserves.

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, 2011, were as follows:

	Gross *	Net **
Productive wells:		
Natural gas	3,465	2,753
Oil	3,853	305
Total	7,318	3,058
Developed acreage (000's)	691	401
Undeveloped acreage set to expire in the years (000's):		
2012	36	23
2013	64	34
2014	88	54
Thereafter	765	404
Total undeveloped acreage	953	515

* Reflects well or acreage in which an interest is owned.

** Reflects Fidelity's percentage of ownership.

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

Delivery Commitments At December 31, 2011, Fidelity has commitments to deliver fixed and determinable amounts of natural gas under contracts of 5.1 Bcf in 2012 and the commitments to deliver natural gas for years subsequent to 2012 are immaterial. Fidelity does not have any material delivery commitments to deliver fixed and determinable amounts of oil at December 31, 2011.

Exploratory and Development Wells The following table reflects activities related to Fidelity's natural gas and oil wells drilled and/or tested during 2011, 2010 and 2009:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2011	**4**	**—**	**4**	**48**	**—**	**48**	**52**
2010	3	4	7	133	1	134	141
2009	1	2	3	104	—	104	107

At December 31, 2011, there were 57 gross (22 net) wells in the process of drilling or under evaluation, 49 of which were development wells and 8 of which were exploratory wells. These wells are not included in the previous table. Fidelity expects to complete the drilling and testing of these wells within the next 12 months.

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

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

Environmental Matters Fidelity's exploration and 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, ESA and other state, federal and local regulations. Administration of many provisions of these laws has been delegated to the states where Fidelity operates. Permit terms vary and all permits carry operational compliance conditions. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand and/or regulatory changes.

Detailed environmental assessments and/or environmental impact statements under federal and state laws are required as part of the permitting process covering the conduct of drilling and production operations as well as in the abandonment and reclamation of facilities.

In connection with production operations, Fidelity has not incurred any material capital environmental expenditures in 2011 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2014.

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. Senior management reviews and approves the reserve estimates to ensure they are materially accurate. The technical person responsible for overseeing the preparation of the reserve estimates holds a bachelor of science degree in geological engineering and a master of science degree in geology, has over 25 years 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 reviewed the Company's proved reserve quantity estimates as of December 31, 2011. The technical person at Ryder Scott primarily responsible for overseeing the reserves audit is a Senior Vice President with over 30 years of experience in estimating and auditing reserves attributable to oil and gas properties, holds a bachelor of science degree in mechanical engineering, is a registered professional engineer, and is a member of multiple professional organizations.

Fidelity's proved reserves by region at December 31, 2011, are as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total	PV-10 Value * (in millions)
Rocky Mountain	280,415	27,410	444,876	76%	$ 1,003.7
Mid-Continent/Gulf States	99,412	6,937	141,032	24	264.7
Total reserves	379,827	34,347	585,908	100%	1,268.4
Discounted future income taxes					289.6
Standardized measure of discounted future net cash flows relating to proved reserves					$ 978.8

* 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 $384 million in backlog at December 31, 2011, compared to $420 million at December 31, 2010. The Company anticipates that a significant amount of the current backlog will be completed during the year ending December 31, 2012.

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 previously are used to calculate the thickness of aggregate materials to be recovered. Topography associated with alluvial sand and gravel deposits is typically flat and volumes of these materials are calculated by applying the thickness of the resource over the areas available for mining. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 1.5 tons per cubic yard in the ground is used for sand and gravel deposits.

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

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 1.0 billion tons of the 1.1 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to be permitted for mining under current regulatory requirements. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining were calculated by dividing remaining reserves by the three-year average sales from 2009 through 2011. 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, 2011, and sales for the years ended December 31, 2011, 2010 and 2009:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves	Lease	Reserve Life
Production Area	owned	leased	owned	leased	**2011**	2010	2009	(000's tons)	Expiration	(years)
Anchorage, AK	—	—	1	—	**137**	854	891	16,563	N/A	26
Hawaii	—	6	—	—	**1,527**	1,412	1,940	60,683	2012-2064	37
Northern CA	—	—	9	1	**1,552**	1,043	1,215	48,298	2014	38
Southern CA	—	2	—	—	**1,134**	619	337	93,135	2035	Over 100
Portland, OR	1	3	5	3	**3,106**	2,521	2,718	242,614	2012-2055	87
Eugene, OR	3	4	4	1	**884**	1,311	1,097	170,063	2013-2046	Over 100
Central OR/ WA/ID	1	2	4	4	**851**	1,192	1,436	105,789	2012-2077	91
Southwest OR	5	4	11	6	**1,604**	1,505	1,871	99,629	2012-2048	60
Central MT	—	—	1	2	**758**	971	1,220	29,667	2013-2027	30
Northwest MT	—	—	7	1	**1,370**	1,362	1,289	45,545	2020	34
Wyoming	—	—	1	2	**461**	447	655	13,133	2013-2019	25
Central MN	—	1	36	27	**1,520**	1,527	1,868	77,217	2012-2028	47
Northern MN	2	—	16	5	**355**	401	838	27,201	2013-2016	51
ND/SD	—	—	3	19	**1,727**	1,106	699	30,199	2012-2031	26
Iowa	—	1	1	8	**249**	642	545	7,703	2012-2020	16
Texas	1	2	1	—	**1,182**	1,648	1,080	21,394	2015-2025	16
Sales from other sources					**6,319**	4,788	4,296			
					24,736	23,349	23,995	1,088,833		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2011, are comprised of 470 million tons that are owned and 619 million tons that are leased. Approximately 58 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 27 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2009 through 2011 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 64 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves.

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

	2011	2010	2009
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,107,396**	1,125,491	1,145,161
Acquisitions	**1,200**	3,600	21,400
Sales volumes*	**(18,417)**	(18,561)	(19,699)
Other**	**(1,346)**	(3,134)	(21,371)
End of year	**1,088,833**	1,107,396	1,125,491

* 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 2014.

Knife River did not incur any material environmental expenditures in 2011 and, except as to what may be ultimately determined with regard to the issue described later, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2014.

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

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

Construction Services

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

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

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2011, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2011, was approximately $308 million compared to $373 million at December 31, 2010. MDU Construction Services expects to complete a significant amount of this backlog during the year ending December 31, 2012. Due to the nature of its contractual arrangements, in many instances MDU Construction Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather MDU Construction Services is committed to perform these services if and to the extent requested by the customer. Therefore, there can be no assurance as to the customers' requirements during a particular period or that such estimates at any point in time are predictive of future revenues.

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

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

to effectively operate in this competitive environment.

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

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

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

MDU Construction Services did not incur any material environmental expenditures in 2011 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2014.

Item 1A. Risk Factors

The Company's business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents that it files with the SEC. The factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Economic Risks

The Company's exploration and production and pipeline and energy services businesses are dependent on factors, including commodity prices and commodity price basis differentials, 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 identify, 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 exploration and 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 involves 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 including its pension and other postretirement benefit plans and, may have a negative impact on the Company's future revenues and cash flows.

The global demand for natural resources, interest 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 the Company's products and services, primarily at the Company's construction businesses. The level of demand for construction products and services could continue to be adversely impacted by the downturn in the industries the Company serves, as well as in the economy in general. State and federal budget issues may continue to negatively affect the funding available for infrastructure spending. This continued economic volatility could have a material adverse effect on the Company's results of operations, cash flows and asset values.

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

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

The Company relies on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as sources of liquidity for capital requirements not satisfied by its cash flow from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans may be adversely affected. Market disruptions or a downgrade of the Company's credit ratings may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:

- A severe prolonged economic downturn
- The bankruptcy of unrelated industry leaders in the same line of business
- Deterioration in capital market conditions
- Turmoil in the financial services industry
- Volatility in commodity prices
- Terrorist attacks

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

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The issuance of a substantial amount of the Company's common stock, whether sold pursuant to the registration statement, issued in connection with an acquisition or otherwise issued, or the perception that such an issuance could occur, may adversely affect the market price of the Company's common stock.

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

If 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 materials and contracting and construction services businesses are subject to delay or cancellation and may not be realized.

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

Actual quantities of recoverable 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 properties. 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

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

The Company is subject to environmental laws and regulations affecting many aspects of its present and future operations, including air quality, water quality, waste management and other environmental considerations. These laws and regulations can result in increased capital, operating and other costs, delays as a result of litigation and administrative proceedings, and compliance, remediation, containment, monitoring and reporting obligations, particularly with regard to laws relating to power plant operations and natural gas and oil 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, install pollution control equipment or initiate 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, that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

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

The EPA finalized a rule in December 2011, that will reduce mercury and other toxic air emissions from coal- and oil-fired electric utility steam generating units. As proposed, air pollution control retrofits, such as baghouses, may be required at company-owned electric generation facilities in order to comply with the rule's emissions limits. Montana-Dakota is evaluating the impact of the final rule on its electric generation resources. Controls must be installed by approximately March 2015. One additional year may be granted by the permitting authority to install pollution controls depending on system reliability issues.

Hydraulic fracturing is an important common practice used by the Company that involves injecting water, sand and chemicals under pressure into rock formations to stimulate natural gas and oil production. The EPA is developing a study to review the potential effects of hydraulic fracturing on underground sources of drinking water; the results of that study have the potential to impact the likelihood or scope of future legislation or regulation. Other legislative initiatives and regulatory studies, proceedings or initiatives at federal or state agencies focused on the hydraulic fracturing process could result in additional compliance, reporting and disclosure requirements. While not materially impacted by current regulation, future legislation or regulation could cause the Company to experience increased compliance and operating costs, as well as delay or inhibit its ability to develop its natural gas and oil reserves.

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

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. The EPA finalized its endangerment finding for GHG emissions in late 2009, and its GHG "Tailoring" Rule in 2010. The GHG "Tailoring" Rule requires new large emission sources, such as coal-fired electric generating facilities, and existing large emission sources that make modifications that increase GHG emissions to obtain permits and conduct best available control technology evaluations to limit the amount of GHG emission from these sources.

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. Approximately 70 percent of Montana-Dakota's owned generating capacity and more than 90 percent of the electricity it generates is from coal-fired plants. Montana-Dakota also owns approximately 100 MW of natural gas- and oil-fired peaking plants.

While the future of GHG regulation is uncertain, Montana-Dakota's electric generating facilities may be subject to 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 expanded energy conservation efforts or increased development of renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs. If Montana-Dakota does not receive timely and full recovery of GHG emission compliance costs from its customers, then such costs could have an adverse impact on the results of its operations.

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

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

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

Other Risks

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

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

Competition is increasing in all of the Company's businesses.

All of the Company's businesses are subject to increased competition. Construction services' competition is based primarily on price and reputation for quality, safety and reliability. 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 exploration and 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 position and cash flows.

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

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

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

Various operating subsidiaries of the Company participate in approximately 70 multiemployer pension plans for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.

The Company may be obligated to increase its contributions to underfunded plans that are classified as being in endangered, seriously endangered, or critical status as defined by the Pension Protection Act of 2006. Plans classified as being in one of these statuses are required to adopt RPs or FIPs to improve their funded status through increased contributions, reduced benefits or a combination of the two. Based on available information, the Company believes that approximately 45 percent of the multiemployer plans to which it contributes are currently in endangered, seriously endangered or critical status.

The Company may also be required to increase its contributions to multiemployer plans where the other participating employers in such plans withdraw from the plan and are not able to contribute an amount sufficient to fund the unfunded liabilities associated with their participants in the plans. The amount and timing of any increase in the Company's required contributions to multiemployer pension plans may also depend upon one or more of the following factors including the outcome of collective bargaining, actions taken by trustees who manage the plans, the industry for which contributions are made, future determinations that additional plans reach endangered, seriously endangered or critical status, government regulations and the actual return on assets held in the plans, among others. The Company may experience increased operating expenses as a result of the required contributions to multiemployer pension plans, which may have a material adverse effect on the Company's results of operations, financial position or cash flows.

In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan to the extent these plans are underfunded.

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

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

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

Other factors that could impact the Company's businesses.

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

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

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings of the Company, see Item 8 - Note 19, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

For information regarding mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K, see Exhibit 95 to this Form 10-K, which is incorporated herein by reference.

Part II

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

The Company's common stock is listed on the New York Stock Exchange under the symbol "MDU." The price range of the Company's common stock as reported by The Wall Street Journal composite tape during 2011 and 2010 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2011			
First quarter	**$23.00**	**$20.11**	**$.1625**
Second quarter	**24.05**	**21.47**	**.1625**
Third quarter	**23.28**	**18.25**	**.1625**
Fourth quarter	**22.19**	**18.00**	**.1675**
			$.6550
2010			
First quarter	$24.15	$19.54	$.1575
Second quarter	22.90	17.11	.1575
Third quarter	20.48	17.61	.1575
Fourth quarter	21.27	19.52	.1625
			$.6350

As of December 31, 2011, the Company's common stock was held by approximately 14,800 stockholders of record.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends see Item 8 - Note 12.

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2011	—			

November 1 through November 30, 2011	49,050	$20.18
December 1 through December 31, 2011	6,091	$20.52
Total	55,141	

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

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

Item 6. Selected Financial Data

	2011	2010	2009 *	2008 **	2007	2006
Selected Financial Data						
Operating revenues (000's):						
Electric	**$ 225,468**	$ 211,544	$ 196,171	$ 208,326	$ 193,367	$ 187,301
Natural gas distribution	**907,400**	892,708	1,072,776	1,036,109	532,997	351,988
Pipeline and energy services	**278,343**	329,809	307,827	532,153	447,063	443,720
Exploration and production	**453,586**	434,354	439,655	712,279	514,854	483,952
Construction materials and contracting	**1,510,010**	1,445,148	1,515,122	1,640,683	1,761,473	1,877,021
Construction services	**854,389**	789,100	819,064	1,257,319	1,103,215	987,582
Other	**11,446**	7,727	9,487	10,501	10,061	8,117
Intersegment eliminations	**(190,150)**	(200,695)	(183,601)	(394,092)	(315,134)	(335,142)
	$ 4,050,492	$ 3,909,695	$ 4,176,501	$ 5,003,278	$ 4,247,896	$ 4,004,539
Operating income (loss) (000's):						
Electric	**$ 49,096**	$ 48,296	$ 36,709	$ 35,415	$ 31,652	$ 27,716
Natural gas distribution	**82,856**	75,697	76,899	76,887	32,903	8,744
Pipeline and energy services	**45,365**	46,310	69,388	49,560	58,026	57,133
Exploration and production	**133,790**	143,169	(473,399)	202,954	227,728	231,802
Construction materials and contracting	**51,092**	63,045	93,270	62,849	138,635	156,104
Construction services	**39,144**	33,352	44,255	81,485	75,511	50,651
Other	**5,024**	858	(219)	2,887	(7,335)	(9,075)
	$ 406,367	$ 410,727	$ (153,097)	$ 512,037	$ 557,120	$ 523,075
Earnings (loss) on common stock (000's):						
Electric	**$ 29,258**	$ 28,908	$ 24,099	$ 18,755	$ 17,700	$ 14,401
Natural gas distribution	**38,398**	36,944	30,796	34,774	14,044	5,680
Pipeline and energy services	**23,082**	23,208	37,845	26,367	31,408	32,126
Exploration and production	**80,282**	85,638	(296,730)	122,326	142,485	145,657
Construction materials and contracting	**26,430**	29,609	47,085	30,172	77,001	85,702
Construction services	**21,627**	17,982	25,589	49,782	43,843	27,851
Other	**6,190**	21,046	7,357	10,812	(4,380)	(4,324)
Earnings (loss) on common stock before income (loss) from discontinued operations	**225,267**	243,335	(123,959)	292,988	322,101	307,093
Income (loss) from discontinued operations, net of tax	**(12,926)**	(3,361)	—	—	109,334	7,979

	$	**212,341**	$	239,974	$	(123,959)	$	292,988	$	431,435	$	315,072

	2011	2010	2009 *	2008 **	2007	2006
Earnings (loss) per common share before discontinued operations - diluted	**$ 1.19**	$ 1.29	$ (.67)	$ 1.59	$ 1.76	$ 1.69
Discontinued operations, net of tax	**(.07)**	(.02)	—	—	.60	.05
	$ 1.12	$ 1.27	$ (.67)	$ 1.59	$ 2.36	$ 1.74
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	**188,905**	188,229	185,175	183,807	182,902	181,392
Dividends declared per common share	**$ .6550**	$ .6350	$ .6225	$ .6000	$ .5600	$ .5234
Book value per common share	**$ 14.62**	$ 14.22	$ 13.61	$ 14.95	$ 13.80	$ 11.88
Market price per common share (year end)	**$ 21.46**	$ 20.27	$ 23.60	$ 21.58	$ 27.61	$ 25.64
Market price ratios:						
Dividend payout	**58%**	50%	N/A	38%	24%	30%
Yield	**3.1%**	3.2%	2.7 %	2.9%	2.1%	2.1%
Price/earnings ratio	**19.2x**	16.0x	N/A	13.6x	11.7x	14.7x
Market value as a percent of book value	**146.8%**	142.5%	173.4 %	144.3%	200.1%	215.8%
Profitability Indicators						
Return on average common equity	**7.8%**	9.1%	(4.9)%	11.0%	18.5%	15.6%
Return on average invested capital	**6.3%**	7.0%	(1.7)%	8.0%	13.1%	10.6%
Fixed charges coverage, including preferred dividends	**4.0x**	4.1x	— ***	5.3x	6.4x	6.4x

* 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.

*** Due to the $384.4 million after-tax noncash write-down of natural gas and oil properties, earnings were insufficient by $228.7 million to cover fixed charges. If the $384.4 million after-tax noncash write-down is excluded, the coverage of fixed charges, including preferred dividends would have been 4.6 times. 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.

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.

	2011	2010	2009	2008	2007	2006
General						
Total assets (000's)	**$ 6,556,125**	$ 6,303,549	$ 5,990,952	$ 6,587,845	$ 5,592,434	$ 4,903,474
Total long-term debt (000's)	**$ 1,424,678**	$ 1,506,752	$ 1,499,306	$ 1,647,302	$ 1,308,463	$ 1,254,582
Capitalization ratios:						
Common equity	**66%**	64%	63%	61%	66%	63%
Total debt	**34**	36	37	39	34	37
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**2,878,852**	2,785,710	2,663,560	2,663,452	2,601,649	2,483,248
Sales for resale (thousand kWh)	**63,899**	58,321	90,789	223,778	165,639	483,944
Electric system summer generating and firm purchase capability - kW (Interconnected system)	**658,900**	594,180	594,700	597,250	571,160	547,485
Electric system summer and firm purchase contract PRCs (Interconnected system)	**572.8**	553.3	*	*	*	*
Electric system peak demand obligation, including firm purchase contracts, PRCs (Interconnected system)	**524.2**	529.5	*	*	*	*
Demand peak - kW (Interconnected system)	**535,761**	525,643	525,643	525,643	525,643	485,456
Electricity produced (thousand kWh)	**2,488,337**	2,472,288	2,203,665	2,538,439	2,253,851	2,218,059
Electricity purchased (thousand kWh)	**645,567**	521,156	682,152	516,654	576,613	833,647
Average cost of fuel and purchased power per kWh	**$ .021**	$ .021	$ .023	$ .025	$ .025	$ .022
Natural Gas Distribution**						
Sales (Mdk)	**103,237**	95,480	102,670	87,924	52,977	34,553
Transportation (Mdk)	**124,227**	135,823	132,689	103,504	54,698	14,058
Degree days (% of normal)						
Montana-Dakota	**101%**	98%	104%	103%	93%	87%
Cascade	**103%**	96%	105%	108%	102%	—
Intermountain	**107%**	100%	107%	90%	—	—
Pipeline and Energy Services						
Transportation (Mdk)	**113,217**	140,528	163,283	138,003	140,762	130,889
Gathering (Mdk)	**66,500**	77,154	92,598	102,064	92,414	87,135
Customer natural gas storage balance (Mdk)	**36,021**	58,784	61,506	30,598	50,219	51,477
Exploration and Production						
Production:						
Natural gas (MMcf)	**45,598**	50,391	56,632	65,457	62,798	62,062
Oil (MBbls)	**3,500**	3,262	3,111	2,808	2,365	2,041
Total production (MMcfe)	**66,596**	69,963	75,299	82,303	76,988	74,307

Average realized prices (including hedges):						
Natural gas (per Mcf)	**$ 3.85**	$ 4.36	$ 5.16	$ 7.38	$ 5.96	$ 6.03
Oil (per Bbl)	**$ 79.43**	$ 65.85	$ 47.38	$ 81.68	$ 59.26	$ 50.64
Average realized prices (excluding hedges):						
Natural gas (per Mcf)	**$ 3.30**	$ 3.57	$ 2.99	$ 7.29	$ 5.37	$ 5.62
Oil (per Bbl)	**$ 83.30**	$ 66.71	$ 49.76	$ 82.28	$ 59.53	$ 51.73
Proved reserves:						
Natural gas (MMcf)	**379,827**	448,397	448,425	604,282	523,737	538,100
Oil (MBbls)	**34,347**	32,867	34,216	34,348	30,612	27,100
Total reserves (MMcfe)	**585,908**	645,596	653,724	810,371	707,409	700,700

	2011	2010	2009	2008	2007	2006
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**24,736**	23,349	23,995	31,107	36,912	45,600
Asphalt (tons)	**6,709**	6,279	6,360	5,846	7,062	8,273
Ready-mixed concrete (cubic yards)	**2,864**	2,764	3,042	3,729	4,085	4,588
Aggregate reserves (000's tons)	**1,088,833**	1,107,396	1,125,491	1,145,161	1,215,253	1,248,099

* Information not available for periods prior to 2010.

** Cascade and Intermountain were acquired on July 2, 2007, and October 1, 2008, respectively.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

The Company's strategy is to apply its expertise in energy and transportation infrastructure industries to increase market share, increase profitability and enhance shareholder value through:

- Organic growth as well as a continued disciplined approach to the acquisition of well-managed companies and properties
- The elimination of system-wide cost redundancies through increased focus on integration of operations and standardization and consolidation of various support services and functions across companies within the organization
- The development of projects that are accretive to earnings per share and return on invested capital

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

The key strategies for each of the Company's business segments and certain related business challenges are summarized below. For a summary of the Company's business segments, see Item 8 - Note 15.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations, including building electric generation, transmission extensions, 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 and environmental regulations. The ability of these segments to grow through acquisitions is subject to significant competition. In addition, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of electric generating facilities and transmission lines and other service facilities 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 impact the price and demand for electricity and natural gas.

Pipeline and Energy Services

Strategy Utilize the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, 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; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other natural gas pipeline and energy services companies.

Exploration and Production

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

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

Construction Materials and Contracting

Strategy Focus on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; 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 permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, 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. The current economic challenges have resulted in increased competition in certain construction markets and lower margins. Continued delays in the multiple year reauthorization of the federal highway bill and volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel, continue to be a concern. This business unit expects to continue cost containment efforts and a greater emphasis on industrial, energy and public works projects.

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.

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

For 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,		**2011**		2010		2009
		(Dollars in millions, where applicable)				
Electric	**$**	**29.2**	$	28.9	$	24.1
Natural gas distribution		**38.4**		37.0		30.8
Pipeline and energy services		**23.1**		23.2		37.8
Exploration and production		**80.3**		85.6		(296.7)
Construction materials and contracting		**26.4**		29.6		47.1
Construction services		**21.6**		18.0		25.6
Other		**6.2**		21.0		7.3
Earnings (loss) before discontinued operations		**225.2**		243.3		(124.0)
Loss from discontinued operations, net of tax		**(12.9)**		(3.3)		—
Earnings (loss) on common stock	**$**	**212.3**	$	240.0	$	(124.0)
Earnings (loss) per common share - basic:						
Earnings (loss) before discontinued operations	**$**	**1.19**	$	1.29	$	(.67)
Discontinued operations, net of tax		**(.07)**		(.01)		—
Earnings (loss) per common share - basic	**$**	**1.12**	$	1.28	$	(.67)
Earnings (loss) per common share - diluted:						
Earnings (loss) before discontinued operations	**$**	**1.19**	$	1.29	$	(.67)
Discontinued operations, net of tax		**(.07)**		(.02)		—
Earnings (loss) per common share - diluted	**$**	**1.12**	$	1.27	$	(.67)
Return on average common equity		**7.8%**		9.1%		(4.9)%

2011 compared to 2010 Consolidated earnings for 2011 decreased $27.7 million from the prior year. This decrease was due to:

- Absence of a $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines, as discussed in Item 8 - Note 4, as well as an increased loss of $9.6 million (after tax) from discontinued operations, as discussed in Item 8 - Note 3. Both of these items are included in the Other category.
- Lower average realized natural gas prices, decreased natural gas production, higher depreciation, depletion and amortization expense, increased lease operating costs, higher production and property taxes and higher general and administrative expense, partially offset by higher average realized oil prices and increased oil production at the exploration and production business

Partially offsetting these decreases were higher workloads and margins in the Western region, as well as higher equipment sales and rental margins, partially offset by lower workloads and margins in the Mountain region at the construction services business.

The pipeline and energy services business experienced lower storage services revenue and decreased transportation and gathering volumes, as well as lower operation and maintenance expense, primarily related to the absence of a natural gas gathering arbitration charge of $16.5 million (after tax).

2010 compared to 2009 Consolidated earnings for 2010 were $240.0 million compared to a loss of $124.0 million in 2009. This increase was due to:

- Absence of the 2009 noncash write-down of natural gas and oil properties of $384.4 million (after tax), higher average realized oil prices, increased oil production and lower general and administrative expense, partially offset by lower average realized natural gas prices, decreased natural gas production and higher production taxes at the exploration and production business
- A $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines, as previously discussed, as well as a $3.3 million (after tax) loss from discontinued operations, as discussed in Item 8 - Note 3. Both of these items are included in the Other category.

Partially offsetting these increases were:

- Lower liquid asphalt oil, ready-mixed concrete and asphalt margins and volumes, as well as decreased construction margins, partially offset by lower selling, general and administrative expense at the construction materials and contracting segment
- Higher operation and maintenance expense, primarily due to a natural gas gathering arbitration charge of $16.5 million (after tax) and lower gathering volumes, partially offset by higher storage services revenue at the pipeline and energy services business

Financial and Operating Data

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

Electric

Years ended December 31,		**2011**		2010		2009
	(Dollars in millions, where applicable)					
Operating revenues	**$**	**225.5**	$	211.6	$	196.2
Operating expenses:						
Fuel and purchased power		**64.5**		63.1		65.7
Operation and maintenance		**70.3**		63.8		60.7
Depreciation, depletion and amortization		**32.2**		27.3		24.7
Taxes, other than income		**9.4**		9.1		8.4
		176.4		163.3		159.5
Operating income		**49.1**		48.3		36.7
Earnings	**$**	**29.2**	$	28.9	$	24.1
Retail sales (million kWh)		**2,878.9**		2,785.7		2,663.5
Sales for resale (million kWh)		**63.9**		58.3		90.8
Average cost of fuel and purchased power per kWh	**$**	**.021**	$	.021	$	.023

2011 compared to 2010 Electric earnings increased $300,000 (1 percent) compared to the prior year due to:

- Higher electric retail sales margins, primarily due to higher rates in North Dakota, Montana and Wyoming
- Increased retail sales volumes of 3 percent, primarily to residential and small commercial and industrial customers, reflecting increased customers and demand
- Lower income taxes of $3.4 million, including an income tax benefit of $1.2 million related to favorable resolution of certain income tax matters, higher production tax credits, as well as a reduction of income taxes associated with benefits

Partially offsetting these increases were:

- Higher operation and maintenance expense of $4.1 million (after tax), primarily increased benefit-related costs, as well as increased contract services
- Increased depreciation, depletion and amortization expense of $3.0 million (after tax), including the effects of higher property, plant and equipment balances
- Lower other income of $2.2 million (after tax), largely lower allowance for funds used during construction related to electric generation projects, which were placed in service in 2010
- Higher net interest expense of $1.4 million (after tax), including lower capitalized interest

2010 compared to 2009 Electric earnings increased $4.8 million (20 percent) compared to the prior year due to:

- Higher electric retail sales margins, primarily due to implementation of higher rates in Wyoming, as well as interim rates in North Dakota
- Higher retail sales volumes of 5 percent, primarily to residential and small commercial and industrial customers, reflecting increased customers and demand

Partially offsetting these increases were:

- Higher operation and maintenance expense of $1.8 million (after tax), primarily costs due to storm damage, as well as expenses at Wygen III, which commenced operation in the second quarter of 2010
- Lower other income of $1.6 million (after tax), primarily lower allowance for funds used during construction related to electric generation projects, which were placed in service in 2010
- Increased depreciation, depletion and amortization expense of $1.6 million (after tax), including the effects of higher property, plant and equipment balances
- Higher net interest expense of $1.3 million (after tax), resulting from higher average borrowings and lower capitalized interest

Natural Gas Distribution

Years ended December 31,	**2011**	2010	2009
	(Dollars in millions, where applicable)		
Operating revenues	**$ 907.4**	$ 892.7	$ 1,072.8
Operating expenses:			
Purchased natural gas sold	**594.6**	589.3	757.6
Operation and maintenance	**137.3**	137.4	140.5
Depreciation, depletion and amortization	**44.6**	43.0	42.7
Taxes, other than income	**48.0**	47.3	55.1
	824.5	817.0	995.9
Operating income	**82.9**	75.7	76.9
Earnings	**$ 38.4**	$ 37.0	$ 30.8
Volumes (MMdk):			
Sales	**103.3**	95.5	102.7
Transportation	**124.2**	135.8	132.7
Total throughput	**227.5**	231.3	235.4
Degree days (% of normal)*			
Montana-Dakota	**101%**	98%	104%
Cascade	**103%**	96%	105%
Intermountain	**107%**	100%	107%
Average cost of natural gas, including transportation, per dk	**$ 5.76**	$ 6.17	$ 7.38

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

2011 compared to 2010 The natural gas distribution business experienced an increase in earnings of $1.4 million (4 percent) compared to the prior year due to increased retail sales volumes and margins, largely resulting from colder weather than last year.

Partially offsetting this increase were:

- Higher regulated operation and maintenance expense of $3.5 million (after tax), primarily higher benefit-related costs
- Higher income taxes of $2.1 million, primarily related to the absence of a 2010 income tax benefit of $4.8 million related to a reduction in deferred income taxes associated with property, plant and equipment, partially offset by a reduction of income taxes associated with benefits
- Lower nonregulated energy-related services of $1.3 million (after tax), largely related to lower pipeline project activity
- Increased depreciation, depletion and amortization expense of $1.0 million (after tax), primarily resulting from higher property, plant and equipment balances

The previous table also reflects lower revenue and lower operation and maintenance expense related to pipeline project activity.

2010 compared to 2009 The natural gas distribution business experienced an increase in earnings of $6.2 million (20 percent) compared to the prior year due to:

- An income tax benefit of $4.8 million, as previously discussed
- Lower operation and maintenance expense of $2.7 million (after tax), largely lower bad debt expense and benefit-related costs

- Higher nonregulated energy-related services of $1.4 million (after tax), including pipeline project activity
- Lower net interest expense of $1.3 million (after tax), primarily due to higher capitalized interest and lower average borrowings
- Higher other income of $1.1 million (after tax), primarily allowance for funds used during construction due to higher rates
- Increased demand-related transportation volumes of $900,000 (after tax), primarily industrial customers

Partially offsetting these increases were decreased retail sales volumes, largely resulting from warmer weather than last year.

Pipeline and Energy Services

Years ended December 31,		**2011**		2010		2009
			(Dollars in millions)			
Operating revenues	**$**	**278.3**	$	329.8	$	307.8
Operating expenses:						
Purchased natural gas sold		**125.3**		153.9		138.8
Operation and maintenance		**68.9**		90.6		63.1
Depreciation, depletion and amortization		**25.5**		26.0		25.5
Taxes, other than income		**13.2**		13.0		11.0
		232.9		283.5		238.4
Operating income		**45.4**		46.3		69.4
Earnings	**$**	**23.1**	$	23.2	$	37.8
Transportation volumes (MMdk)		**113.2**		140.5		163.3
Gathering volumes (MMdk)		**66.5**		77.2		92.6
Customer natural gas storage balance (MMdk):						
Beginning of period		**58.8**		61.5		30.6
Net injection (withdrawal)		**(22.8)**		(2.7)		30.9
End of period		**36.0**		58.8		61.5

2011 compared to 2010 Pipeline and energy services earnings decreased $100,000 largely due to:

- Lower storage services revenue of $7.1 million (after tax), largely lower storage balances
- Decreased transportation volumes of $4.6 million (after tax), largely lower volumes transported to storage resulting from decreased customer demand, as well as lower off-system transportation volumes
- Lower gathering volumes of $3.9 million (after tax), largely resulting from customers experiencing normal production declines

Partially offsetting the earnings decrease was lower operation and maintenance expense, primarily related to the absence of the natural gas gathering arbitration charge of $26.6 million ($16.5 million after tax) in 2010, as discussed in Item 8 - Note 19, partially offset by the absence of an insurance recovery that lowered costs in 2010 related to natural gas storage litigation. The natural gas storage litigation was settled in July 2009.

2010 compared to 2009 Pipeline and energy services earnings decreased $14.6 million (39 percent) largely due to:

- Higher operation and maintenance expense, primarily due to a natural gas gathering arbitration charge of $26.6 million ($16.5 million after tax), partially offset by lower costs related to natural gas storage litigation, largely due to an insurance recovery; both as previously discussed
- Lower gathering volumes of $4.2 million (after tax), largely resulting from customers experiencing normal production declines
- Decreased transportation volumes of $2.0 million (after tax), largely lower volumes transported to storage resulting from decreased customer demand

Partially offsetting the earnings decrease was higher storage services revenue of $6.0 million (after tax), largely higher storage balances.

Exploration and Production

Years ended December 31,		2011		2010		2009
		(Dollars in millions, where applicable)				
Operating revenues:						
Natural gas	$	**175.6**	$	219.6	$	292.3
Oil		**278.0**		214.8		147.4
		453.6		434.4		439.7
Operating expenses:						
Operation and maintenance:						
Lease operating costs		**75.6**		68.5		70.1
Gathering and transportation		**24.3**		23.5		24.0
Other		**36.5**		32.5		39.2
Depreciation, depletion and amortization		**142.6**		130.5		129.9
Taxes, other than income:						
Production and property taxes		**40.8**		35.5		29.1
Other		**—**		.7		.8
Write-down of natural gas and oil properties		**—**		—		620.0
		319.8		291.2		913.1
Operating income (loss)		**133.8**		143.2		(473.4)
Earnings (loss)	$	**80.3**	$	85.6	$	(296.7)
Production:						
Natural gas (MMcf)		**45,598**		50,391		56,632
Oil (MBbls)		**3,500**		3,262		3,111
Total production (MMcfe)		**66,596**		69,963		75,299
Average realized prices (including hedges):						
Natural gas (per Mcf)	$	**3.85**	$	4.36	$	5.16
Oil (per Bbl)	$	**79.43**	$	65.85	$	47.38
Average realized prices (excluding hedges):						
Natural gas (per Mcf)	$	**3.30**	$	3.57	$	2.99
Oil (per Bbl)	$	**83.30**	$	66.71	$	49.76
Average depreciation, depletion and amortization rate, per equivalent Mcf	$	**2.04**	$	1.77	$	1.64
Production costs, including taxes, per equivalent Mcf:						
Lease operating costs	$	**1.13**	$	.98	$	.93
Gathering and transportation		**.36**		.34		.32
Production and property taxes		**.61**		.51		.39
	$	**2.10**	$	1.83	$	1.64

2011 compared to 2010 Earnings at the exploration and production business decreased $5.3 million (6 percent) due to:

- Lower average realized natural gas prices of 12 percent
- Decreased natural gas production of 10 percent, largely related to normal production declines at certain properties, partially offset by increased production from the South Texas properties resulting from drilling activity, as well as production from the Green River Basin properties, which were acquired in April 2010
- Higher depreciation, depletion and amortization expense of $7.6 million (after tax), due to higher depletion rates, partially offset by lower volumes
- Increased lease operating expenses of $4.4 million (after tax) largely related to higher well maintenance costs, including higher workover costs at the Cedar Creek Anticline properties, in which the Company holds a net profits interest; costs from the Green

River Basin properties, which were acquired in April 2010; as well as higher costs resulting from increased production in the Bakken area and at the South Texas properties
- Higher production and property taxes of $3.3 million (after tax), largely resulting from higher oil prices excluding hedges
- Higher general and administrative expense of $2.0 million (after tax), largely higher payroll-related costs

Partially offsetting these decreases were:

- Higher average realized oil prices of 21 percent
- Increased oil production of 7 percent, largely related to drilling activity at the South Texas properties, as well as in the Bakken area, partially offset by normal production declines at certain properties

2010 compared to 2009 The exploration and production business reported earnings of $85.6 million in 2010 compared to a loss of $296.7 million in 2009 due to:

- Absence of the 2009 noncash write-down of natural gas and oil properties of $384.4 million (after tax), as discussed in Item 8 - Note 1
- Higher average realized oil prices of 39 percent
- Increased oil production of 5 percent, largely related to drilling activity in the Bakken area, partially offset by normal production declines at certain existing properties
- Lower general and administrative expense of $4.2 million (after tax), including the absence of rig contract termination costs in 2009
- Lower net interest expense of $1.3 million (after tax), primarily due to lower average borrowings and higher capitalized interest, partially offset by higher effective interest rates

Partially offsetting these increases were:

- Lower average realized natural gas prices of 16 percent
- Decreased natural gas production of 11 percent, largely related to normal production declines at existing properties, partially offset by production from the Green River Basin properties, which were acquired in April 2010, as discussed in Item 8 - Note 2
- Higher production and property taxes of $4.0 million (after tax), largely resulting from higher natural gas and oil prices excluding hedges

Construction Materials and Contracting

Years ended December 31,		**2011**		2010		2009
			(Dollars in millions)			
Operating revenues	**$**	**1,510.0**	$	1,445.1	$	1,515.1
Operating expenses:						
Operation and maintenance		**1,337.4**		1,260.4		1,292.0
Depreciation, depletion and amortization		**85.5**		88.3		93.6
Taxes, other than income		**36.0**		33.4		36.2
		1,458.9		1,382.1		1,421.8
Operating income		**51.1**		63.0		93.3
Earnings	**$**	**26.4**	$	29.6	$	47.1
Sales (000's):						
Aggregates (tons)		**24,736**		23,349		23,995
Asphalt (tons)		**6,709**		6,279		6,360
Ready-mixed concrete (cubic yards)		**2,864**		2,764		3,042

2011 compared to 2010 Earnings at the construction materials and contracting business decreased $3.2 million (11 percent) due to:

- Lower earnings of $5.8 million (after tax) resulting from lower liquid asphalt oil margins, largely due to higher asphalt oil costs
- Lower earnings of $3.3 million (after tax) resulting from lower other product line margins, largely due to lower revenues and higher costs
- Lower earnings of $2.3 million (after tax) resulting from lower ready-mixed concrete margins, primarily due to higher costs

Partially offsetting the decreases were:

- Increased construction margins of $5.4 million (after tax), largely due to increased margins and volumes in the Pacific, North Central and Mountain regions
- Lower interest expense of $2.3 million (after tax), primarily due to lower average interest rates

2010 compared to 2009 Earnings at the construction materials and contracting business decreased $17.5 million (37 percent) due to:

- Lower earnings of $11.1 million (after tax), as a result of lower liquid asphalt oil margins and volumes, largely due to increased competition
- Lower earnings of $7.3 million (after tax) resulting from lower ready-mixed concrete margins and volumes, primarily due to less available work and increased competition
- Decreased construction margins of $7.1 million (after tax), largely due to increased competition
- Lower earnings of $5.7 million (after tax) resulting from lower asphalt margins and volumes, primarily due to increased competition, as well as higher asphalt oil costs

Partially offsetting the decreases were lower selling, general and administrative expense of $8.2 million (after tax) and higher gains on the sale of property, plant and equipment of $5.5 million (after tax). Increased competition is largely the result of the continuing economic downturn in the residential and commercial markets.

Construction Services

Years ended December 31,		**2011**		2010		2009
				(In millions)		
Operating revenues	**$**	**854.4**	$	789.1	$	819.0
Operating expenses:						
Operation and maintenance		**778.5**		719.7		736.3
Depreciation, depletion and amortization		**11.4**		12.1		12.8
Taxes, other than income		**25.4**		23.9		25.7
		815.3		755.7		774.8
Operating income		**39.1**		33.4		44.2
Earnings	**$**	**21.6**	$	18.0	$	25.6

2011 compared to 2010 Construction services earnings increased $3.6 million (20 percent) compared to the prior year, primarily due to higher workloads and margins in the Western region, higher equipment sales and rental margins, as well as decreased general and administrative expense of $1.1 million (after tax). The earnings increase was partially offset by lower workloads and margins in the Mountain region, as well as lower margins in the Central region.

2010 compared to 2009 Construction services earnings decreased $7.6 million (30 percent) compared to the prior year, primarily due to lower construction workloads and margins, which reflect the effects of the economic downturn. Lower general and administrative expense of $7.9 million (after tax), largely lower payroll-related costs and lower bad debt expense partially offset the earnings decrease. Lower construction workloads and margins in the Western and Central regions were partially offset by higher construction workloads and margins in the Mountain region.

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,		**2011**		2010		2009
				(In millions)		
Other:						
Operating revenues	**$**	**11.4**	$	7.7	$	9.5
Operation and maintenance		**4.7**		4.8		8.1
Depreciation, depletion and amortization		**1.6**		1.6		1.3
Taxes, other than income		**.1**		.5		.3
Intersegment transactions:						
Operating revenues	**$**	**190.1**	$	200.7	$	183.6

Purchased natural gas sold	**147.7**	175.4	156.7
Operation and maintenance	**42.4**	25.3	26.9

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 2012, diluted, are projected in the range of $1.00 to $1.25. The Company expects the approximate percentage of 2012 earnings per common share by quarter to be:
    - First quarter - 15 percent
    - Second quarter - 15 percent
    - Third quarter - 40 percent
    - Fourth quarter - 30 percent
- Although near term market conditions are uncertain, the Company's 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 and natural gas distribution

- The South Dakota Board of Minerals and Environment has approved rules implementing the South Dakota Regional Haze Program that upon approval by the EPA will require the Big Stone Station to install and operate a BART air quality control system to reduce emissions of particulate matter, sulfur dioxide and nitrogen oxides as early as practicable, but not later than five years after EPA's approval of the state program. The state program was submitted January 21, 2011. The Company's share of the cost of this air quality control system is estimated at $125 million. The Company believes continuing to operate Big Stone Station with the upgrade is the best option. The Company intends to seek recovery of costs related to the above matter in electric rates charged to customers. On May 20, 2011, the Company filed for an advance determination of prudence with the NDPSC requesting advance determination that the air quality control system is reasonable and prudent, as discussed in Item 8 - Note 18.
- On July 7, 2011, the Company filed for an advance determination of prudence with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities, as discussed in Item 8 - Note 18.
- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors with company and customer-owned pipeline facilities designed to serve existing facilities currently served by fuel oil or propane, and to serve new customers.
- Currently the Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system in the Pacific Northwest.
- The Company is pursuing opportunities associated with the potential development of high-voltage transmission lines and system enhancements targeted towards delivery of renewable energy from the wind rich regions that lie within its traditional electric service territory to major market areas. The Company has a contract to develop a 30-mile high-voltage power line in southeast North Dakota to move power to the electric grid from a proposed 150-MW wind farm. The proposed project totals approximately $18 million and includes substation upgrades. Construction is underway and the project is expected to be completed by mid 2012.

Pipeline and energy services

- The Company expects lower customer storage balances in 2012 compared to 2011. In addition, the anticipated divestment of certain natural gas properties and the deferral of certain gas development activity at our exploration and production business are expected to result in gathering volumes being lower in 2012 compared to 2011. These declines are expected to be partially offset by higher transportation volumes related to growth projects placed in service in the Bakken area.
- 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 of North Dakota and eastern Montana. The Company owns an extensive natural gas pipeline system in the Bakken area. Ongoing energy development is expected to have many direct and indirect benefits to this business.

- Installation of additional compression at the Charbonneau station was completed and placed into service in September 2011, providing additional firm capacity for producers in the Bakken production area. With some additional modifications, this project has the potential of adding a total of 27 MMcf of firm capacity.

- Construction was completed in December 2011 on approximately 12 miles of high pressure transmission pipeline providing takeaway capacity from the Garden Creek processing facility in northwestern North Dakota.

- Preparations are underway for the construction of approximately 13 miles of high pressure transmission pipeline from the Stateline I and II processing facilities in northwestern North Dakota to deliver gas into the Northern Border Pipeline. The project is expected to be completed by mid 2012.

- The Company has three natural gas storage fields including the largest storage field in North America located near Baker, Montana. It continues to seek interest in its storage services and is pursuing a project to increase its firm deliverability from the Baker Storage field by 125 MMcf per day. Commitment on approximately 30 percent of the total potential project was received and the additional firm deliverability became available in November 2011.

Exploration and production

- The Company expects to spend approximately $400 million in capital expenditures in 2012. The Company continues its focus on returns by allocating the majority of its capital investment into the production of oil in the current commodity price environment. Its capital program reflects further exploitation of existing properties, acquisition of additional leasehold acreage, and exploratory drilling. The 2012 planned capital expenditure total does not include potential acquisitions of producing properties.

- For 2012, the Company expects a 20 percent to 30 percent increase in oil production and a 12 percent to 16 percent decrease in natural gas production. The projected decline in natural gas production is primarily the result of the anticipated divestment of certain natural gas properties and the deferral of certain natural gas development activity because of sustained low natural gas prices.

- The Company has a total of 8 drilling rigs deployed on its acreage in the Bakken, Niobrara, Texas, Paradox, Heath Shale and Big Horn areas, up from 2 rigs in the first quarter of 2011. Dependent upon results during 2012, further growth in rig activity could occur.

- Bakken Area

    - The Company holds a total of approximately 95,000 net acres of leaseholds.

    - Capital expenditures are expected to total approximately $160 million in 2012; approximately $60 million higher than the capital spent for 2011.

    - Mountrail County, North Dakota

        - The Company holds approximately 16,000 net acres of leaseholds targeting the middle Bakken and Three Forks formations.

        - The drilling of 17 operated and participation in various non-operated wells is expected for 2012 with approximately $75 million of capital expenditures.

        - Over 50 future gross well sites have been identified. Estimated gross ultimate recovery per well is 250,000 to 500,000 Bbls.

    - Stark County, North Dakota

        - The Company holds approximately 50,000 net exploratory leasehold acres, targeting the Three Forks formation.

        - The drilling of 7 operated wells and participation in various non-operated wells is expected for 2012 with approximately $60 million of capital expenditures.

        - Based on 640-acre spacing, approximately 140 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 400,000 Bbls.

    - Richland County, Montana

        - The Company has increased its acreage to approximately 30,000 net exploratory leasehold acres, targeting the Three Forks formation.

        - The first appraisal well is expected to be spud in the first quarter of 2012 and a total of 5 operated wells are planned for this year with approximately $25 million of capital expenditures.

        - Approximately 100 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 400,000 Bbls.

- Niobrara - southeastern Wyoming

    - The Company holds approximately 65,000 net exploratory leasehold acres.

    - The drilling of 4 operated wells and participation in various non-operated wells is expected for 2012 with approximately $25 million of capital expenditures.

    - Approximately 200 potential gross well sites have been identified based on 640-acre spacing. Estimated gross ultimate recovery rates per well are 200,000 to 300,000 Bbls.

- Paradox Basin - Cane Creek Federal Unit, Utah

    - The Company holds approximately 75,000 net exploratory leasehold acres.

    - The drilling of 4 operated wells is expected in 2012 with capital expenditures of approximately $35 million.

    - Approximately 70 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 500,000 Bbls.

- Texas

    - The Company is targeting areas that have the potential for higher liquids content with approximately $60 million of capital planned for 2012.

    - Plans are to drill 20 operated wells in Texas in 2012.

    - Approximately 50 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 400,000 Bbls.

- Heath Shale

    - The Company holds approximately 90,000 net exploratory leasehold acres in the Heath Shale oil prospect in Montana and expects to drill between 2 and 4 wells in 2012 with capital of approximately $20 million.

- Other Opportunities

    - The Company continues to pursue acquisitions of additional leaseholds. Approximately $25 million of capital has been allocated to leasehold acquisitions, focusing on expansion of existing positions and new opportunities.

    - The remaining forecasted 2012 capital has been allocated to other operated and non-operated opportunities.

- Reserve information
  - The Company's combined proved natural gas and oil reserves as of December 31, 2011, were 586 Bcfe.
  - Reserve additions replaced annual production, however, there were approximately 60 Bcfe of negative revisions to last year's estimates. Approximately 85 percent of the negative revisions were associated with natural gas properties. Revisions of prior estimates, low natural gas prices and a change in strategy to focus on oil properties led to a significant reduction in the number of PUD reserves associated with natural gas properties.
  - Oil reserves are 5 percent higher than a year ago primarily the result of approximately 60 percent growth in Bakken reserves. The Company's oil reserve replacement ratio was 175 percent for 2011, excluding revisions.
  - Natural gas reserves are 15 percent lower primarily for the reasons mentioned previously. The biggest changes occurred in the dry gas fields of Baker and Bowdoin.
  - With increasing oil reserves as well as higher oil prices, the combined PV-10 value of proved oil and natural gas reserves grew by more than 10 percent year-over-year.
- Earnings guidance reflects estimated natural gas and oil prices for February through December as follows:

Natural Gas Index:	
NYMEX	$2.50 to $3.00 per Mcf
Crude Oil Index:	
NYMEX	$95.00 to $102.00 per Bbl
Note: Estimated prices do not reflect potential basis differentials.	

- For 2012, the Company has hedged approximately 30 percent to 35 percent of its estimated natural gas production and 65 percent to 70 percent of its estimated oil production. For 2013, the Company has hedged 30 percent to 35 percent of its estimated oil production. The hedges that are in place as of February 17, 2012, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (MMBtu/Bbl)	Price (Per MMBtu/Bbl)
Natural Gas	Swap	NYMEX	1/12 - 12/12	3,477,000	$6.27
Natural Gas	Swap	NYMEX	1/12 - 12/12	1,830,000	$5.005
Natural Gas	Swap	NYMEX	1/12 - 12/12	915,000	$5.005
Natural Gas	Swap	NYMEX	1/12 - 12/12	915,000	$5.0125
Natural Gas	Swap	Ventura	1/12 - 12/12	3,660,000	$4.87
Natural Gas	Swap	NYMEX	4/12 - 12/12	2,750,000	$3.05
Crude Oil	Collar	NYMEX	1/12 - 12/12	366,000	$80.00-$87.80
Crude Oil	Collar	NYMEX	1/12 - 12/12	366,000	$80.00-$94.50
Crude Oil	Collar	NYMEX	1/12 - 12/12	366,000	$80.00-$98.36
Crude Oil	Collar	NYMEX	1/12 - 12/12	183,000	$85.00-$102.75
Crude Oil	Collar	NYMEX	1/12 - 12/12	183,000	$85.00-$103.00
Crude Oil	Swap	NYMEX	1/12 - 12/12	183,000	$100.10
Crude Oil	Swap	NYMEX	1/12 - 12/12	183,000	$100.00
Crude Oil	Swap	NYMEX	1/12 - 12/12	366,000	$110.30
Crude Oil	Swap	NYMEX	1/12 - 12/12	366,000	$96.00
Crude Oil	Swap	NYMEX	1/12 - 12/12	366,000	$99.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$95.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$95.30
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$100.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$100.02
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$102.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$102.00
Crude Oil	Collar	NYMEX	1/13 - 12/13	182,500	$95.00-$117.00
Crude Oil	Collar	NYMEX	1/13 - 12/13	182,500	$95.00-$117.00
Crude Oil	Collar	NYMEX	1/13 - 12/13	365,000	$90.00-$97.05
Natural Gas	Basis Swap	CIG	1/12 - 12/12	2,745,000	$0.405
Natural Gas	Basis Swap	CIG	1/12 - 12/12	732,000	$0.41

Notes:

- 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.
- For all basis swaps, Index prices are below NYMEX prices and are reported as a positive amount in the Price column.

Construction materials and contracting

- Work backlog as of December 31, 2011, was approximately $384 million, with 92 percent of construction backlog being public work and private representing 8 percent. Backlog a year ago was approximately $420 million. Examples of projects in work backlog include several highway paving projects, airports, bridge work, reclamation and harbor expansion projects.

- The Company has green fielded an operation in Williston in the Bakken area of North Dakota and currently has $31 million of backlog in the area. The Company is pursuing substantial growth opportunities associated with the Bakken area.

- The Company is part of a joint venture that was selected as the low bidder on the Port of Long Beach expansion. Its share of the project for this phase is expected to exceed $25 million. It also placed a new approximately 35,000 ton asphalt oil terminal into service in December 2011 in Wyoming. The Company is the primary cement provider in Hawaii and has the opportunity to supply a portion of the ready-mixed concrete and aggregate related to an approximate $5 billion multi-phased light rail project.

- Projected revenues included in the Company's 2012 earnings guidance are in the range of $1.3 billion to $1.4 billion.

- The Company anticipates margins in 2012 to be higher than 2011 levels.

- 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.

- As the country's 5th largest sand and gravel producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

Construction services

- Work backlog as of December 31, 2011, was approximately $308 million, compared to approximately $373 million a year ago. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including refinery work.

- Projected revenues included in the Company's 2012 earnings guidance are in the range of $700 million to $800 million.

- The Company anticipates margins in 2012 to be higher than 2011 levels.

- The Company is pursuing expansion in high-voltage transmission and substation construction, renewable resource construction, governmental facilities, refinery turnaround projects and utility service work.

New Accounting Standards

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

Critical Accounting Policies Involving Significant Estimates

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

Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the acquisition 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.

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. The extent, quality and reliability of this data can vary. 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.

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

The Company uses the full-cost method of accounting for its exploration and production activities. Under this method,

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

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 at least annually for goodwill.

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

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2011, 2010 and 2009, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach.

Under the discounted cash flow method, fair value is based on the estimated future cash flows of each reporting unit, discounted to present value using their respective weighted average cost of capital. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and peer data for each respective reporting unit.

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

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

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

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. Critical estimates related to the recognition of revenue include 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. These estimates are based on the Company's analysis of its as-filed application compared to previous regulatory 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. If a loss is anticipated on a contract, the loss is immediately recognized.

The Company believes its estimates surrounding percentage-of-completion accounting are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job.

Pension and other postretirement benefits

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

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases and healthcare cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers historical returns, current market conditions and expected future market trends, including changes in interest rates and equity and bond market performance. Another key variable in determining benefit expense or income is the discount rate. In selecting the discount rate, the Company matches forecasted future cash flows of the pension and postretirement plans to a yield curve which consists of a hypothetical portfolio of high-quality corporate bonds with varying maturity dates, as well as other factors, as a basis. The Company's pension and other postretirement benefit plan assets are primarily made up of equity and fixed-income investments. Fluctuations in actual equity and bond market returns as well as changes in general interest rates may result in increased or decreased pension and other postretirement benefit costs in the future. Management estimates the rate of compensation increase based on long-term assumed wage increases and the healthcare cost trend rates are determined by historical and future trends. The Company estimates that a 25 basis point decrease in the discount rate or in the expected return on plan assets would each increase expense by less than $1.0 million (after tax) for the year ended December 31, 2011.

The Company believes the estimates made for its pension and other postretirement benefits are reasonable based on the information that is known when the estimates are made. These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will be affected by changes in the discount rate, the expected long-term return on plan assets, the rate of compensation increase and healthcare cost trend rates. The Company plans to continue to use its current methodologies to determine plan costs. For additional information on the assumptions used in determining plan costs, see Item 8 - Note 16.

Income taxes

Income taxes require significant judgments and estimates including the determination of income tax expense, deferred tax assets and liabilities and, if necessary, any valuation allowances that may be required for deferred tax assets and accruals for uncertain tax positions. The effective income tax rate is subject to variability from period to period as a result of changes in federal and state income tax rates and/or changes in tax laws. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states. The Company estimates that a one percent change in the effective tax rate would affect income tax expense by approximately $3.4 million for the year ended December 31, 2011.

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 positions in income taxes.

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

Liquidity and Capital Commitments

At December 31, 2011, the Company had cash and cash equivalents of $162.8 million and available capacity of $583.4 million under the outstanding credit facilities of the Company and its subsidiaries.

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 2011 increased $75.0 million from the comparable prior period. The increase was primarily due to higher deferred income taxes of $52.3 million, largely the result of bonus depreciation, as well as lower working capital requirements of $15.6 million, primarily at the electric and natural gas distribution businesses.

Cash flows provided by operating activities in 2010 decreased $295.1 million from the comparable prior period. The decrease was primarily due to higher working capital requirements of $238.0 million resulting mainly from decreased cash provided from receivables at the construction businesses and lower cash provided from natural gas costs recoverable through rate adjustments at the natural gas distribution business. In addition, excluding working capital requirements, the Company experienced decreased cash flows from operating activities at the construction and exploration and production businesses, partially offset by increased cash flows from operating activities at the electric and natural gas distribution businesses.

Investing activities Cash flows used in investing activities in 2011 increased $56.6 million from the comparable prior period due to:

- Lower proceeds from the sale of the Company's equity method investments in the Brazilian Transmission Lines of $66.3 million
- Increased ongoing capital expenditures of $47.7 million, largely at the construction materials and contracting business
- Lower proceeds from the sale or disposition of properties and other of $36.3 million, largely at the exploration and

production business

Partially offsetting the increase in cash flows used in investing activities was lower cash used for acquisitions of $104.7 million, primarily at the exploration and production business.

Cash flows used in investing activities in 2010 decreased $24.2 million from the comparable prior period due to:

- Proceeds from the sale of the Company's equity method investments in the Brazilian Transmission Lines of $69.1 million
- Higher proceeds from the sale or disposition of properties and other of $49.7 million, largely at the exploration and production business and construction materials and contracting business

Partially offsetting the decrease in cash flows used in investing activities were increased acquisition-related capital expenditures of $98.4 million, largely due to the acquisition of natural gas properties in the Green River Basin.

Financing activities Cash flows used in financing activities in 2011 increased $124.4 million from the comparable prior period, largely resulting from higher repayment of long-term debt and short-term borrowings of $71.5 million and $9.7 million, respectively, as well as lower issuance of short-term borrowings and long-term debt of $20.0 million and $19.9 million, respectively.

Cash flows used in financing activities in 2010 decreased $195.2 million from the comparable prior period, primarily due to lower repayment of short-term borrowings and long-term debt of $94.8 million and $279.2 million, respectively, offset in part by lower issuance of long-term debt of $124.8 million and lower issuance of common stock of $60.2 million. Lower cash used in financing activities reflects the effects of proceeds from the sale of the Company's equity method investments and higher net proceeds from the sale and disposition of property and other, as previously discussed.

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, 2011, the Pension Plans' accumulated benefit obligations exceeded these plans' assets by approximately $157.6 million. Pretax pension expense reflected in the years ended December 31, 2011, 2010 and 2009, was $3.7 million, $1.0 million and $8.2 million, respectively. The Company's pension expense is currently projected to be approximately $2.0 million to $3.0 million in 2012. Funding for the Pension Plans is actuarially determined. The minimum required contributions for 2011, 2010 and 2009 were approximately $9.3 million, $6.4 million and $7.3 million, respectively. For further information on the Company's Pension Plans, see Item 8 - Note 16.

Capital expenditures

The Company's capital expenditures for 2009 through 2011 and as anticipated for 2012 through 2014 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual 2009	Actual 2010	Actual **2011**	Estimated* 2012	Estimated* 2013	Estimated* 2014
			(In millions)			
Capital expenditures:						
Electric	$ 115	$ 86	**$ 52**	$ 109	$ 141	$ 143
Natural gas distribution	44	75	**71**	108	104	74
Pipeline and energy services	70	14	**45**	32	67	77
Exploration and production	183	356	**273**	400	439	434
Construction materials and contracting	27	26	**52**	45	43	54
Construction services	13	15	**10**	12	13	12
Other	3	2	**19**	1	1	1
Net proceeds from sale or disposition of property and other	(27)	(79)	**(41)**	(9)	(1)	—
Net capital expenditures	428	495	**481**	698	807	795
Retirement of long-term debt	293	14	**85**	139	267	9
	$ 721	$ 509	**$ 566**	$ 837	$ 1,074	$ 804

* 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.

Capital expenditures for 2011, 2010 and 2009 in the preceding table include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions. The net noncash transactions were $24.0 million in 2011, $17.5 million in 2010 and immaterial in 2009.

The 2011 capital expenditures, including those for the retirement of long-term debt, were met from internal sources and the issuance of long-term debt and the Company's equity securities. Estimated capital expenditures for the years 2012 through 2014 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, acquisition of additional leasehold acreage and exploratory drilling at the exploration and production segment
- Power generation opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. It is anticipated that all of the funds required for capital expenditures and retirement of long-term debt for the years 2012 through 2014 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.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2011. 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, 2011:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date
					(Dollars in millions)				
MDU Resources Group, Inc.	Commercial paper/ Revolving credit agreement	(a)	$ 100.0		$ —	(b)	$ —		5/26/15
Cascade Natural Gas Corporation	Revolving credit agreement		$ 50.0	(c)	$ —		$ 1.9	(d)	12/28/12 (e)
Intermountain Gas Company	Revolving credit agreement		$ 65.0	(f)	$ 8.1		$ —		8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement	(g)	$ 400.0		$ —	(b)	$ 21.6	(d)	12/13/12

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 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) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letters of credit, as discussed in Item 8 - Note 19, reduce amounts available under the credit agreement.
(e) Provisions allow for an extension of up to two years upon consent of the banks.
(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(g) 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.

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

The following includes information related to the preceding table.

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. 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 downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

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

The Company's coverage of fixed charges including preferred stock dividends was 4.0 times and 4.1 times for the 12 months ended December 31, 2011 and 2010, respectively.

Common stockholders' equity as a percent of total capitalization was 66 percent and 64 percent at December 31, 2011 and 2010, respectively. This ratio is calculated as the Company's common stockholders' equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus stockholders' equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

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

The Company's board of directors reviews this authorization on a periodic basis and the aggregate amount of securities authorized may be increased in the future.

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

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

Off balance sheet arrangements

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

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 derivative instruments, long-term debt, operating leases and purchase commitments, see Item 8 - Notes 7, 9 and 19. At December 31, 2011, the Company's commitments under these obligations were as follows:

	2012	2013	2014	2015	2016	Thereafter	Total
				(In millions)			
Long-term debt	$ 139.3	$ 267.3	$ 9.3	$ 266.4	$ 288.4	$ 454.0	$ 1,424.7
Estimated interest payments*	84.3	69.8	62.2	58.3	37.6	245.0	557.2
Operating leases	27.8	24.3	16.4	8.6	5.8	35.9	118.8
Purchase commitments	478.0	215.9	135.8	71.1	36.7	287.0	1,224.5
Commodity derivatives	13.2	.9	—	—	—	—	14.1
Interest rate derivatives	.8	4.0	—	—	—	—	4.8
	$ 743.4	$ 582.2	$ 223.7	$ 404.4	$ 368.5	$ 1,021.9	$ 3,344.1

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

Not reflected in the table above are $11.2 million in uncertain tax positions. For more information, see Item 8 - Note 14.

The Company's minimum funding requirements for its defined benefit pension plans for 2012, which are not reflected in the previous table, are $15.9 million. For information on potential contributions above the minimum funding requirements, see Item 8 - Note 16.

The Company's multiemployer plan contributions are based on union employee payroll, which cannot be determined in advance for future periods. The Company may also be required to make additional contributions to its multiemployer plans if they become underfunded. For more information, see Item 1A - Risk Factors and Item 8 - Note 16.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2011, 2010 or 2009.

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 utilizes, and Intermountain periodically utilizes, 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 and Cascade as of December 31, 2011. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade 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 2012	$ 5.37	10,797	$ 22,970
Natural gas basis swap agreements maturing in 2012	$ .41	3,477	$ (801)
Oil swap agreements maturing in 2012	$ 101.34	1,464	$ 3,694
Oil swap agreements maturing in 2013	$ 95.15	365	$ (229)
Cascade			
Natural gas swap agreement maturing in 2012	$ 4.47	305	$ (437)
	Weighted Average Floor/ Ceiling Price (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Fidelity			
Oil collar agreements maturing in 2012	$81.25/$95.88	1,464	$ (10,904)
Oil collar agreements maturing in 2013	$92.50/$107.03	730	$ 2,061

The following table summarizes derivative agreements entered into by Fidelity and Cascade as of December 31, 2010. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade 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 2011	$ 5.69	12,666	$ 14,501
Natural gas swap agreement maturing in 2012	$ 6.27	3,477	$ 4,104
Natural gas basis swap agreements maturing in 2011	$ .27	8,115	$ (256)
Natural gas basis swap agreements maturing in 2012	$ .41	3,477	$ (33)
Oil swap agreements maturing in 2011	$ 82.85	548	$ (5,961)
Cascade			
Natural gas swap agreements maturing in 2011	$ 8.10	2,270	$ (9,359)

	Weighted Average Floor/Ceiling Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas collar agreement maturing in 2011	$5.62/$6.50	450	$ 579
Oil collar agreements maturing in 2011	$78.86/$90.64	1,278	$ (8,319)
Oil collar agreements maturing in 2012	$80.00/$93.55	1,098	$ (6,450)

	Deferred Premium	Weighted Average Floor (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Fidelity				
Oil put agreement maturing in 2011	$ 4.00	$ 80.00	365	$ (490)

Interest rate risk

The Company uses fixed and variable rate long-term debt to partially finance capital expenditures and mandatory debt retirements. These debt agreements expose the Company to market risk related to changes in interest rates. The Company manages this risk by taking advantage of market conditions when timing the placement of long-term or permanent financing. The Company from time to time uses interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk.

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

The following table summarizes derivative instruments entered into by Centennial as of December 31, 2011. The agreements call for Centennial to receive variable rates and pay fixed rates. The Company had no outstanding interest rate hedges at December 31, 2010.

(Notional amount and fair value in thousands)

	Weighted Average Fixed Interest Rate	Notional Amount	Fair Value
Centennial			
Interest rate swap agreement with mandatory termination date in 2012	3.15%	$ 10,000	$ (827)
Interest rate swap agreements with mandatory termination dates in 2013	3.22%	$ 50,000	$ (3,935)

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, 2011.

	2012	2013	2014	2015	2016	Thereafter	Total	Fair Value
	(Dollars in millions)							
Long-term debt:								
Fixed rate	$ 139.3	$ 259.2	$ 9.3	$ 266.4	$ 288.4	$ 454.0	$ 1,416.6	$ 1,584.7
Weighted average interest rate	5.8%	6.0%	6.9%	5.7%	6.4%	6.1%	6.1%	—
Variable rate	—	$ 8.1	—	—	—	—	$ 8.1	$ 8.1
Weighted average interest rate	—	2.5%	—	—	—	—	2.5%	—

Foreign currency risk

The Company's equity method investment in ECTE is exposed to market risks from changes in foreign currency exchange rates between the U.S. dollar and the Brazilian Real. For further information, see Item 8 - Note 4. At December 31, 2011 and 2010, the Company had no outstanding foreign currency hedges.

Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

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

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011. 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, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, 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 President and Chief Executive Officer	Doran N. Schwartz Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2011 and 2010, 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, 2011. Our audits also included the financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MDU Resources Group, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

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, 2011, 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 24, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2012

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, 2011, 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, 2011, 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 schedules as of and for the year ended December 31, 2011 of the Company and our report dated February 24, 2012 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2012

MDU RESOURCES GROUP, INC.

Consolidated Statements of Income

Years ended December 31,	2011	2010	2009
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	**$ 1,343,714**	$ 1,359,028	$ 1,504,269
Exploration and production, construction materials and contracting, construction services and other	**2,706,778**	2,550,667	2,672,232
Total operating revenues	**4,050,492**	3,909,695	4,176,501
Operating expenses:			
Fuel and purchased power	**64,485**	63,065	65,717
Purchased natural gas sold	**572,187**	567,806	739,678
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	**275,866**	291,524	263,869
Exploration and production, construction materials and contracting, construction services and other	**2,215,269**	2,084,377	2,143,195
Depreciation, depletion and amortization	**343,395**	328,843	330,542
Taxes, other than income	**172,923**	163,353	166,597
Write-down of natural gas and oil properties (Note 1)	**—**	—	620,000
Total operating expenses	**3,644,125**	3,498,968	4,329,598
Operating income (loss)	**406,367**	410,727	(153,097)
Earnings from equity method investments	**4,693**	30,816	8,499
Other income	**6,520**	8,018	9,331
Interest expense	**81,354**	83,011	84,099
Income (loss) before income taxes	**336,226**	366,550	(219,366)
Income taxes	**110,274**	122,530	(96,092)
Income (loss) from continuing operations	**225,952**	244,020	(123,274)
Loss from discontinued operations, net of tax (Note 3)	**(12,926)**	(3,361)	—
Net income (loss)	**213,026**	240,659	(123,274)
Dividends declared on preferred stocks	**685**	685	685
Earnings (loss) on common stock	**$ 212,341**	$ 239,974	$ (123,959)
Earnings (loss) per common share - basic:			
Earnings (loss) before discontinued operations	**$ 1.19**	$ 1.29	$ (.67)
Discontinued operations, net of tax	**(.07)**	(.01)	—
Earnings (loss) per common share - basic	**$ 1.12**	$ 1.28	$ (.67)
Earnings (loss) per common share - diluted:			
Earnings (loss) before discontinued operations	**$ 1.19**	$ 1.29	$ (.67)
Discontinued operations, net of tax	**(.07)**	(.02)	—
Earnings (loss) per common share - diluted	**$ 1.12**	$ 1.27	$ (.67)
Dividends declared per common share	**$ .6550**	$ .6350	$ .6225
Weighted average common shares outstanding - basic	**188,763**	188,137	185,175
Weighted average common shares outstanding - diluted	**188,905**	188,229	185,175

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

MDU RESOURCES GROUP, INC.

Consolidated Balance Sheets

December 31,	2011	2010
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ **162,772**	$ 222,074
Receivables, net	**646,251**	583,743
Inventories	**274,205**	252,897
Deferred income taxes	**40,407**	32,890
Commodity derivative instruments	**27,687**	15,123
Prepayments and other current assets	**43,316**	60,441
Total current assets	**1,194,638**	1,167,168
Investments	**109,424**	103,661
Property, plant and equipment (Note 1)	**7,646,222**	7,218,503
Less accumulated depreciation, depletion and amortization	**3,361,208**	3,103,323
Net property, plant and equipment	**4,285,014**	4,115,180
Deferred charges and other assets:		
Goodwill (Note 5)	**634,931**	634,633
Other intangible assets, net (Note 5)	**20,843**	25,271
Other	**311,275**	257,636
Total deferred charges and other assets	**967,049**	917,540
Total assets	$ **6,556,125**	$ 6,303,549
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings (Note 9)	$ **—**	$ 20,000
Long-term debt due within one year	**139,267**	72,797
Accounts payable	**337,228**	301,132
Taxes payable	**70,176**	56,186
Dividends payable	**31,794**	30,773
Accrued compensation	**47,804**	40,121
Commodity derivative instruments	**13,164**	24,428
Other accrued liabilities	**259,320**	222,639
Total current liabilities	**898,753**	768,076
Long-term debt (Note 9)	**1,285,411**	1,433,955
Deferred credits and other liabilities:		
Deferred income taxes	**769,166**	672,269
Other liabilities	**827,228**	736,447
Total deferred credits and other liabilities	**1,596,394**	1,408,716
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, $1.00 par value		
Issued - 189,332,485 shares in 2011 and 188,901,379 shares in 2010	**189,332**	188,901
Other paid-in capital	**1,035,739**	1,026,349
Retained earnings	**1,586,123**	1,497,439
Accumulated other comprehensive loss	**(47,001)**	(31,261)
Treasury stock at cost - 538,921 shares	**(3,626)**	(3,626)
Total common stockholders' equity	**2,760,567**	2,677,802
Total stockholders' equity	**2,775,567**	2,692,802
Total liabilities and stockholders' equity	**$ 6,556,125**	$ 6,303,549

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, 2011, 2010 and 2009

	Common Stock		Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock		Total
	Shares	Amount				Shares	Amount	
				(In thousands, except shares)				
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 declared on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends declared on common stock	—	—	—	(115,832)	—	—	—	(115,832)
Net tax deficit 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
Comprehensive income:								
Net income	—	—	—	240,659	—	—	—	240,659
Other comprehensive income (loss), net of tax -								
Net unrealized gain on derivative instruments qualifying as hedges	—	—	—	—	673	—	—	673
Postretirement liability adjustment	—	—	—	—	(5,730)	—	—	(5,730)
Foreign currency translation adjustment	—	—	—	—	(5,371)	—	—	(5,371)
Total comprehensive income	—	—	—	—	—	—	—	230,231
Dividends declared on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends declared on common stock	—	—	—	(119,574)	—	—	—	(119,574)
Tax benefit on stock-based compensation	—	—	924	—	—	—	—	924
Issuance of common stock	512,114	512	9,747	—	—	—	—	10,259
Balance at December 31, 2010	188,901,379	188,901	1,026,349	1,497,439	(31,261)	(538,921)	(3,626)	2,677,802

Comprehensive income:								
Net income	—	—	—	213,026	—	—	—	213,026
Other comprehensive income (loss), net of tax -								
Net unrealized gain on derivative instruments qualifying as hedges	—	—	—	—	7,900	—	—	7,900
Postretirement liability adjustment	—	—	—	—	(22,427)	—	—	(22,427)
Foreign currency translation adjustment	—	—	—	—	(1,295)	—	—	(1,295)
Net unrealized gains on available-for-sale investments	—	—	—	—	82	—	—	82
Total comprehensive income	—	—	—	—	—	—	—	197,286
Dividends declared on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends declared on common stock	—	—	—	(123,657)	—	—	—	(123,657)
Net tax deficit on stock-based compensation	—	—	(909)	—	—	—	—	(909)
Issuance of common stock	431,106	431	10,299	—	—	—	—	10,730
Balance at December 31, 2011	**189,332,485**	**$ 189,332**	**$ 1,035,739**	**$ 1,586,123**	**$ (47,001)**	**(538,921)**	**$ (3,626)**	**$ 2,760,567**

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

MDU RESOURCES GROUP, INC.

Consolidated Statements of Cash Flows

Years ended December 31,	2011	2010	2009
		(In thousands)	
Operating activities:			
Net income (loss)	$ **213,026**	$ 240,659	$ (123,274)
Loss from discontinued operations, net of tax	**(12,926)**	(3,361)	—
Income (loss) from continuing operations	**225,952**	244,020	(123,274)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**343,395**	328,843	330,542
Earnings, net of distributions, from equity method investments	**(2,111)**	(26,158)	(3,018)
Deferred income taxes	**118,925**	66,585	(169,764)
Write-down of natural gas and oil properties (Note 1)	**—**	—	620,000
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(30,452)**	(59,037)	132,939
Inventories	**(24,226)**	(4,728)	13,969
Other current assets	**7,729**	(7,424)	67,803
Accounts payable	**(12,263)**	17,833	(61,867)
Other current liabilities	**33,738**	12,289	44,039
Other noncurrent changes	**(33,365)**	(20,271)	(4,683)
Net cash provided by continuing operations	**627,322**	551,952	846,686
Net cash used in discontinued operations	**(674)**	(319)	—
Net cash provided by operating activities	**626,648**	551,633	846,686
Investing activities:			
Capital expenditures	**(497,000)**	(449,282)	(448,675)
Acquisitions, net of cash acquired	**(157)**	(104,812)	(6,410)
Net proceeds from sale or disposition of property and other	**40,107**	76,386	26,679
Investments	**(10,302)**	704	(3,740)
Proceeds from sale of equity method investments	**2,807**	69,060	—
Net cash used in continuing operations	**(464,545)**	(407,944)	(432,146)
Net cash provided by discontinued operations	—	—	—
Net cash used in investing activities	**(464,545)**	(407,944)	(432,146)
Financing activities:			
Issuance of short-term borrowings	**—**	20,000	10,300
Repayment of short-term borrowings	**(20,000)**	(10,300)	(105,100)
Issuance of long-term debt	**300**	20,200	145,000
Repayment of long-term debt	**(85,151)**	(13,668)	(292,907)
Proceeds from issuance of common stock	**5,744**	4,972	65,207
Dividends paid	**(123,323)**	(119,157)	(115,023)
Tax benefit on stock-based compensation	**1,239**	1,186	601
Net cash used in continuing operations	**(221,191)**	(96,767)	(291,922)
Net cash provided by discontinued operations	—	—	—
Net cash used in financing activities	**(221,191)**	(96,767)	(291,922)
Effect of exchange rate changes on cash and cash equivalents	**(214)**	38	782

Increase (decrease) in cash and cash equivalents		**(59,302)**		46,960		123,400
Cash and cash equivalents - beginning of year		**222,074**		175,114		51,714
Cash and cash equivalents - end of year	**$**	**162,772**	$	222,074	$	175,114

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

Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

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

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

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

Management has also evaluated the impact of events occurring after December 31, 2011, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents

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

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $29.8 million and $21.6 million as of December 31, 2011 and 2010, respectively. For more information, see Percentage-of-completion method in this note.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2011 and 2010, was $12.4 million and $15.3 million, respectively.

Inventories and natural gas in storage

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

	2011	2010
	(In thousands)	
Aggregates held for resale	**$ 78,518**	$ 79,894
Materials and supplies	**61,611**	57,324
Natural gas in storage (current)	**36,578**	34,557
Asphalt oil	**32,335**	25,234
Merchandise for resale	**32,165**	30,182

Other		**32,998**		25,706
Total	**$**	**274,205**	$	252,897

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $50.3 million and $48.0 million at December 31, 2011 and 2010, respectively.

Investments

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

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and production properties as described in 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 $15.1 million, $17.6 million and $17.4 million in 2011, 2010 and 2009, 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 exploration and 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:

	2011	2010	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 546,783	$ 538,071	47
Distribution	255,232	243,205	36
Transmission	179,580	161,972	44
Other	86,929	83,786	13
Natural gas distribution:			
Distribution	1,257,360	1,223,239	38
Other	311,506	285,606	23
Pipeline and energy services:			
Transmission	386,227	357,395	52
Gathering	42,378	41,931	19
Storage	41,908	33,967	51
Other	36,179	33,938	29
Nonregulated:			
Pipeline and energy services:			
Gathering	198,864	203,064	17
Other	13,735	13,512	10
Exploration and production:			
Natural gas and oil properties	2,577,576	2,320,967	*
Other	37,570	35,971	9
Construction materials and contracting:			
Land	126,790	124,018	—
Buildings and improvements	67,627	65,003	20
Machinery, vehicles and equipment	902,136	899,365	12
Construction in progress	8,085	4,879	—
Aggregate reserves	395,214	393,110	**
Construction services:			
Land	4,706	4,526	—
Buildings and improvements	15,001	14,101	22
Machinery, vehicles and equipment	95,891	94,252	7
Other	9,198	10,061	4
Other:			
Land	2,837	2,837	—
Other	46,910	29,727	24
Less accumulated depreciation, depletion and amortization	3,361,208	3,103,323	
Net property, plant and equipment	$ 4,285,014	$ 4,115,180	

* Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $2.04, $1.77 and $1.64 for the years ended December 31, 2011, 2010 and 2009, respectively. Includes natural gas and oil properties accounted for

under the full-cost method, of which $232.5 and $182.4 million were excluded from amortization at December 31, 2011 and 2010, respectively.

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

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and 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 2011, 2010 and 2009. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

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

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach. If the fair value of a reporting unit is less than its carrying value, step two of the goodwill impairment test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the affected reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2011, 2010 and 2009, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded. 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 generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, 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 at March 31, 2009, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2009. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-down amounted to $620.0 million ($384.4 million after tax) for the year ended December 31, 2009.

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, 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, 2011, 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, 2011, 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, 2011, in total and by the year in which such costs were incurred:

	Total	Year Costs Incurred 2011	2010	2009	2008 and prior
	(In thousands)				
Acquisition	$ 185,773	$ 50,721	$ 71,315	$ 988	$ 62,749
Development	9,938	9,689	156	2	91
Exploration	27,439	24,389	2,710	72	268
Capitalized interest	9,312	3,539	3,096	44	2,633
Total costs not subject to amortization	$ 232,462	$ 88,338	$ 77,277	$ 1,106	$ 65,741

Costs not subject to amortization as of December 31, 2011, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Texas properties, Niobrara play, the Paradox Basin, the Green River Basin and the Big Horn Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $80.2 million and $87.3 million at December 31, 2011 and 2010, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs and estimated earnings in excess of billings on uncompleted contracts of $54.3 million and $46.6 million at December 31, 2011 and 2010, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $79.1 million and $65.2 million at December 31, 2011 and 2010, 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 $51.5 million and $51.1 million at December 31, 2011 and 2010, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $49.3 million and $50.4 million at December 31, 2011 and 2010, respectively. The long-term retainage which was included in deferred charges and other assets - other was $2.2 million and $700,000 at December 31, 2011 and 2010, 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 sales of 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. 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. For more information, see Note 8.

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

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

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $45.1 million and $37.0 million at December 31, 2011 and 2010, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $2.6 million and $6.6 million at December 31, 2011 and 2010, 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 positions in income taxes.

Foreign currency translation adjustment

The functional currency of the Company's investment in ECTE, 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 an average of the 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 2011 and 2010, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury. Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2011	2010	2009 *
		(In thousands)	
Weighted average common shares outstanding - basic	**188,763**	188,137	185,175
Effect of dilutive stock options and performance share awards	**142**	92	—
Weighted average common shares outstanding - diluted	**188,905**	188,229	185,175

* Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.

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 acquisition 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,		**2011**		2010		2009
				(In thousands)		
Interest, net of amount capitalized	**$**	**78,133**	$	80,962	$	81,267
Income taxes paid (refunded), net	**$**	**(12,287)**	$	46,892	$	39,807

For the year ended December 31, 2011, cash flows from investing activities do not include $24.0 million of capital expenditures, including amounts being financed with accounts payable, and therefore, do not have an impact on cash flows for the period.

New accounting standards

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 were effective on January 1, 2011. The guidance requires additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance is effective for the Company on January 1, 2012. The guidance will require additional disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The guidance, except for the portion that was indefinitely deferred, is effective for the Company on January 1, 2012, and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosure, but it will not impact the Company's results of operations, financial position or cash flows.

Disclosures about an Employer's Participation in a Multiemployer Plan In September 2011, the FASB issued guidance on an employer's participation in multiemployer benefit plans. The guidance was issued to enhance the transparency of disclosures about the significant multiemployer plans in which employers participate, the level of the employer's participation in those plans, the financial health of the plans and the nature of the employer's commitments to the plans. This guidance was effective for the Company on December 31, 2011, and must be applied retrospectively. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

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 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 loss, and their related tax effects for the years ended December 31 were as follows:

	2011	2010	2009
		(In thousands)	
Other comprehensive 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 $4,683, $(1,867) and $(2,509) in 2011, 2010 and 2009, respectively	**$ 7,900**	$ (3,077)	$ (4,094)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $0, $(2,305) and $29,170 in 2011, 2010 and 2009, respectively	**—**	(3,750)	47,590
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**7,900**	673	(51,684)
Postretirement liability adjustment, net of tax of $(13,573), $(3,609) and $6,291 in 2011, 2010 and 2009, respectively	**(22,427)**	(5,730)	9,918
Foreign currency translation adjustment, net of tax of $(832), $(3,486) and $6,814 in 2011, 2010 and 2009, respectively	**(1,295)**	(5,371)	10,568
Net unrealized gains on available-for-sale investments, net of tax of $44 in 2011	**82**	—	—
Total other comprehensive loss	**$ (15,740)**	$ (10,428)	$ (31,198)

The after-tax components of accumulated other comprehensive loss as of December 31, 2011, 2010 and 2009, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2009	$ (2,298)	$ (25,163)	$ 6,628	$ —	$ (20,833)
Balance at December 31, 2010	$ (1,625)	$ (30,893)	$ 1,257	$ —	$ (31,261)
Balance at December 31, 2011	**$ 6,275**	**$ (53,320)**	**$ (38)**	**$ 82**	**$ (47,001)**

Note 2 - Acquisitions

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

In 2010, the Company acquired natural gas properties in the Green River Basin in southwest Wyoming. The total purchase consideration for these properties and purchase price adjustments with respect to certain other acquisitions made prior to 2010, consisting of the Company's common stock and cash, was $106.4 million.

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.

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

Note 3 - Discontinued Operations

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In 2011, the Company also incurred legal expenses related to this matter and in the first quarter had an income tax benefit related to favorable resolution of certain tax matters. In the fourth quarter of 2010, the

Company established an accrual for an indemnification claim by Bicent. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For further information, see Note 19.

Note 4 - Equity Method Investments

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2011 and 2010, include ECTE.

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

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale and recognized a gain of $22.7 million ($13.8 million after tax). The Company's entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE was sold. The remaining interest in ECTE is being purchased by one of the parties over a four-year period. In November 2011, the Company completed the sale of one-fourth of the remaining interest and recognized a gain of $1.0 million ($600,000 after tax). The gains are recorded in earnings from equity method investments on the Consolidated Statements of Income. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE.

At December 31, 2011 and 2010, the Company's equity method investments had total assets of $111.1 million and $107.4 million, respectively, and long-term debt of $37.1 million and $30.1 million, respectively. The Company's investment in its equity method investments was approximately $9.2 million and $10.9 million, including undistributed earnings of $3.7 million and $1.9 million, at December 31, 2011 and 2010, respectively.

Note 5 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2011, were as follows:

	Balance as of January 1, 2011 *	Goodwill Acquired During the Year **	Balance as of December 31, 2011 *
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	9,737	—	9,737
Exploration and production	—	—	—
Construction materials and contracting	176,290	—	176,290
Construction services	102,870	298	103,168
Other	—	—	—
Total	$ 634,633	$ 298	$ 634,931

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

The changes in the carrying amount of goodwill for the year ended December 31, 2010, were as follows:

	Balance as of January 1, 2010 *	Goodwill Acquired During the Year **	Balance as of December 31, 2010 *
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	7,857	1,880	9,737
Exploration and production	—	—	—
Construction materials and contracting	175,743	547	176,290
Construction services	100,127	2,743	102,870
Other	—	—	—
Total	$ 629,463	$ 5,170	$ 634,633

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

	2011	2010
	(In thousands)	
Customer relationships	**$ 21,702**	$ 24,942
Accumulated amortization	**(10,392)**	(11,625)
	11,310	13,317
Noncompete agreements	**7,685**	9,405
Accumulated amortization	**(5,371)**	(6,425)
	2,314	2,980
Other	**11,442**	13,217
Accumulated amortization	**(4,223)**	(4,243)
	7,219	8,974
Total	**$ 20,843**	$ 25,271

Amortization expense for intangible assets for the years ended December 31, 2011, 2010 and 2009, was $3.7 million, $4.2 million and $5.0 million, respectively. Estimated amortization expense for intangible assets is $3.8 million in 2012, $3.7 million in 2013, $3.3 million in 2014, $2.6 million in 2015, $2.1 million in 2016 and $5.3 million thereafter.

Note 6 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period *	2011	2010
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	**171,492**	103,818
Deferred income taxes	**	**119,189**	114,427
Taxes recoverable from customers (a)	—	**12,433**	11,961
Plant costs (a)	Over plant lives	**10,256**	9,964
Long-term debt refinancing costs (a)	Up to 27 years	**10,112**	11,101
Costs related to identifying generation development (a)	Up to 15 years	**9,817**	13,777
Natural gas supply derivatives (b)	Up to 1 year	**437**	9,359
Natural gas cost recoverable through rate adjustments (b)	Up to 28 months	**2,622**	6,609
Other (a) (b)	Largely within 1 year	**22,651**	35,225
Total regulatory assets		**359,009**	316,241
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		**289,972**	276,652
Deferred income taxes**		**84,963**	64,017
Natural gas costs refundable through rate adjustments (d)		**45,064**	36,996
Taxes refundable to customers (c)		**31,837**	19,352
Other (c) (d)		**8,393**	16,080
Total regulatory liabilities		**460,229**	413,097
Net regulatory position		**(101,220)**	(96,856)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
** Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.
(a) Included in deferred charges and other assets on the Consolidated Balance Sheets.
(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.
(c) Included in other liabilities on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of December 31, 2011, approximately $216.4 million of regulatory assets were not earning a rate of return.

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

Note 7 - Derivative Instruments

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

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2011, the Company had no outstanding foreign currency hedges.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2011 and 2010, credit risk was not material.

Cascade and Intermountain

At December 31, 2011, Cascade held a natural gas swap agreement with total forward notional volumes of 305,000 MMBtu, which was not designated as a hedge. Cascade utilizes, and Intermountain periodically utilizes, 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. Periodic changes in the fair market value of the derivative instruments are recorded 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 years ended December 31, 2011 and 2010, the change in the fair market value of the derivative instruments of $8.9 million and $18.5 million, respectively, were recorded as a decrease to 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 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's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $437,000. 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, 2011, was $437,000.

Fidelity

At December 31, 2011, Fidelity held natural gas swap agreements with total forward notional volumes of 10.8 million MMBtu, natural gas basis swap agreements with total forward notional volumes of 3.5 million MMBtu, and oil swap and collar agreements with total forward notional volumes of 4.0 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.

As of December 31, 2011, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 24 months.

Centennial

At December 31, 2011, Centennial held interest rate swap agreements with a total notional amount of $60.0 million, which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. Centennial's interest rate swap agreements have mandatory termination dates ranging from October 2012 through June 2013.

Fidelity and Centennial

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).

To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the year ended December 31, 2011, $1.8 million (before tax) of hedge ineffectiveness related to natural gas and oil derivative instruments was reclassified as a gain into operating revenues and is reflected on the Consolidated Statements of Income. The amount of hedge ineffectiveness was immaterial for the years ended December 31, 2010 and 2009, 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 the natural gas and oil derivative instruments are reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the natural gas and oil quantities are settled. The proceeds received for natural gas and oil production are generally based on market prices. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings. 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.

Based on December 31, 2011, fair values, over the next 12 months net gains of approximately $8.7 million (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices and interest rates, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $18.4 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, 2011, was $18.4 million.

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

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 27,687	$ 15,123
	Other assets - noncurrent	2,768	4,104
		30,455	19,227
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	—	—
	Other assets - noncurrent	—	—
		—	—
Total asset derivatives		$ 30,455	$ 19,227

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 12,727	$ 15,069
	Other liabilities - noncurrent	937	6,483
Interest rate derivatives	Other accrued liabilities	827	—
	Other liabilities - noncurrent	3,935	—
		18,426	21,552
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	437	9,359
	Other liabilities - noncurrent	—	—
		437	9,359
Total liability derivatives		$ 18,863	$ 30,911

Note 8 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments 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 $38.4 million and $39.5 million as of December 31, 2011 and 2010, respectively, are classified as Investments on the Consolidated Balance Sheets. The decrease in the fair value of these investments for the year ended December 31, 2011, was $1.1 million (before tax). The increase in the fair value of these investments for the years ended December 31, 2010 and 2009, was $5.8 million (before tax) and $7.1 million (before tax), respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its remaining available-for-sale securities, which include auction rate securities, mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. The Company's 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. Unrealized gains or losses on mortgage-backed securities and U.S. Treasury securities are recorded in accumulated other comprehensive income (loss) as discussed in Note 1. Details of available-for-sale securities were as follows:

December 31, 2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Insurance investment contract	$ 31,884	$ 6,468	$ —	$ 38,352
Auction rate securities	11,400	—	—	11,400
Mortgage-backed securities	8,206	95	(5)	8,296
U.S. Treasury securities	1,619	37	—	1,656
Total	$ 53,109	$ 6,600	$ (5)	$ 59,704

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

	Fair Value Measurements at December 31, 2011, 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, 2011
	(In thousands)			
Assets:				
Money market funds	$ —	$ 97,500	$ —	$ 97,500
Available-for-sale securities:				
Insurance investment contract*	—	38,352	—	38,352
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,296	—	8,296
U.S. Treasury securities	—	1,656	—	1,656
Commodity derivative instruments - current	—	27,687	—	27,687
Commodity derivative instruments - noncurrent	—	2,768	—	2,768
Total assets measured at fair value	$ —	$ 187,659	$ —	$ 187,659
Liabilities:				
Commodity derivative instruments - current	$ —	$ 13,164	$ —	$ 13,164
Commodity derivative instruments - noncurrent	—	937	—	937
Interest rate derivative instruments - current	—	827	—	827
Interest rate derivative instruments - noncurrent	—	3,935	—	3,935
Total liabilities measured at fair value	$ —	$ 18,863	$ —	$ 18,863

* The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

	Fair Value Measurements at December 31, 2010, 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, 2010
	(In thousands)			
Assets:				
Money market funds	$ —	$ 166,620	$ —	$ 166,620
Available-for-sale securities:				
Insurance investment contract*	—	39,541	—	39,541
Auction rate securities	—	11,400	—	11,400
Commodity derivative instruments - current	—	15,123	—	15,123
Commodity derivative instruments - noncurrent	—	4,104	—	4,104
Total assets measured at fair value	$ —	$ 236,788	$ —	$ 236,788
Liabilities:				
Commodity derivative instruments - current	$ —	$ 24,428	$ —	$ 24,428
Commodity derivative instruments - noncurrent	—	6,483	—	6,483
Total liabilities measured at fair value	$ —	$ 30,911	$ —	$ 30,911

* The insurance investment contract invests approximately 35 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 31 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources such as the fund itself.

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2011 and 2010, there were no significant transfers between Levels 1 and 2.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only, and 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:

	2011		2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			

Long-term debt	**$ 1,424,678**	**$ 1,592,807**	$ 1,506,752	$ 1,621,184

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, 2011. 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, 2011		Amount Outstanding at December 31, 2010		Letters of Credit at December 31, 2011		Expiration Date
							(Dollars in millions)				
MDU Resources Group, Inc.	Commercial paper/ Revolving credit agreement	(a)	$ 100.0		$ —	(h)	$ 20.0	(b)	$ —		5/26/15
Cascade Natural Gas Corporation	Revolving credit agreement		$ 50.0	(c)	$ —		$ —		$ 1.9	(d)	12/28/12 (e)
Intermountain Gas Company	Revolving credit agreement		$ 65.0	(f)	$ 8.1		$ 20.2		$ —		8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement	(g)	$ 400.0		$ —	(h)	$ —	(h)	$ 21.6	(d)	12/13/12

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 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 that was classified as short-term borrowings because the revolving credit agreement expired within one year.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.
(e) Provisions allow for an extension of up to two years upon consent of the banks.
(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(g) 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.
(h) Amount outstanding under commercial paper program.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings as of December 31, 2011, would have been classified as short-term borrowings because the revolving credit agreement expires within one year. Any commercial paper borrowings as of December 31, 2010, would have been classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement contains 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. Other covenants include restrictions on the sale of certain assets and on the making of certain loans and investments.

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

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.

Long-term debt

MDU Resources Group, Inc. On May 26, 2011, the Company entered into a new revolving credit agreement, which replaced the revolving credit agreement that expired on June 21, 2011. The Company's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings under this agreement would be classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The commercial paper borrowings outstanding as of December 31, 2010, were classified as short-term borrowings because the previous revolving credit agreement expired within one year.

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

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

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

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 a specified amount, (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 that is in excess of $10 million, then Intermountain shall be in default under the revolving credit agreement.

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired in 2010; however, there is debt outstanding that is reflected in the following table. The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain’s total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

Centennial Energy Holdings, Inc. The ability to request additional borrowings under an uncommitted long-term master shelf agreement expired; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term master shelf agreement contains 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 60 percent. 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.

Williston Basin Interstate Pipeline Company The ability to request additional borrowings under the uncommitted long-term private shelf agreement expired December 23, 2011; however, there is debt outstanding that is reflected in the following table. 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:

	2011	2010
	(In thousands)	
Senior Notes at a weighted average rate of 6.01%, due on dates ranging from May 15, 2012 to March 8, 2037	**$ 1,287,576**	$ 1,358,848
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	**40,469**	41,189
Credit agreements at a weighted average rate of 2.98%, due on dates ranging from September 30, 2012 to November 30, 2038	**15,633**	25,715
Total long-term debt	**1,424,678**	1,506,752
Less current maturities	**139,267**	72,797
Net long-term debt	**$ 1,285,411**	$ 1,433,955

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2011, aggregate $139.3 million in 2012; $267.3 million in 2013; $9.3 million in 2014; $266.4 million in 2015; $288.4 million in 2016 and $454.0 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 facilities and buildings, and certain other obligations.

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

	2011	2010
	(In thousands)	
Balance at beginning of year	**$ 95,970**	$ 76,359
Liabilities incurred	**3,870**	8,608
Liabilities acquired	**—**	5,272
Liabilities settled	**(10,418)**	(10,740)
Accretion expense	**4,466**	3,588
Revisions in estimates	**3,921**	12,621
Other	**342**	262

Balance at end of year	**$**	**98,151**	$	95,970

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, 2011 and 2010, was $5.7 million and $5.7 million, respectively.

Note 11 - Preferred Stocks

Preferred stocks at December 31 were as follows:

		2011		2010
		(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

For the years 2011, 2010 and 2009, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

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

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

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

Note 12 - Common Stock

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 2009 through December 2011, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2011, 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 the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The most restrictive limitations are discussed below.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to

100 percent of Centennial's consolidated net income after taxes for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.2 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2011. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $136 million of the Company's (excluding its subsidiaries) net assets would be restricted from use for dividend payments at December 31, 2011. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2011, there are 6.3 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense was $3.5 million, net of income taxes of $2.2 million in 2011; $3.4 million, net of income taxes of $2.1 million in 2010; and $3.4 million, net of income taxes of $2.2 million in 2009.

As of December 31, 2011, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.5 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock options

The Company had granted stock options to directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vested after nine years, but the plan provided for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expired ten years after the date of grant. Options granted to employees vested three years after the date of grant and expired ten years after the date of grant. Options granted to directors vested at the date of grant and expire ten 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, 2011, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	440,984	$13.34
Forfeited	(3,893)	13.22
Exercised	(430,341)	13.34
Balance at end of year	6,750	13.03
Exercisable at end of year	6,750	$13.03

Stock options outstanding as of December 31, 2011, had an aggregate intrinsic value of $57,000, and approximately six months of remaining contractual life. The aggregate intrinsic value represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2011, which would have been received by the option holders had all option holders exercised their options as of that date.

The Company received cash of $5.7 million, $5.0 million and $2.1 million from the exercise of stock options for the years ended December 31, 2011, 2010 and 2009, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009, was $3.3 million, $2.6 million and $1.3 million, respectively.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 55,141 shares with a fair value of $1.1 million, 43,128 shares with a fair value of $849,000 and 49,649 shares with a fair value of $879,000 issued under this plan during the years ended December 31, 2011, 2010 and 2009, 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, 2011, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2009	2009-2011	257,836
March 2010	2010-2012	227,009
February 2011	2011-2013	277,309

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2011, 2010 and 2009 were:

	2011	2010	2009
Grant-date fair value	**$19.99**	$17.40	$20.39
Blended volatility range	**23.20% - 32.18%**	25.69% - 35.36%	40.40% - 50.98%
Risk-free interest rate range	**.09% - 1.34%**	.13% - 1.45%	.30% - 1.36%
Discounted dividends per share	**$1.23**	$1.04	$1.79

There were no performance shares that vested in 2011. The fair value of performance share awards that vested during the years ended December 31, 2010 and 2009, was $3.5 million and $2.8 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2011, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	669,685	$ 22.19
Granted	278,252	19.99
Vested	—	—
Forfeited	(185,783)	30.55
Nonvested at end of period	762,154	$ 19.35

Note 14 - Income Taxes

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

	2011	2010	2009
		(In thousands)	
United States	**$ 333,486**	$ 336,450	$ (227,021)
Foreign	**2,740**	30,100	7,655
Income (loss) before income taxes from continuing operations	**$ 336,226**	$ 366,550	$ (219,366)

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

	2011	2010	2009
		(In thousands)	
Current:			
Federal	$ (7,188)	$ 37,014	$ 64,389
State	778	10,589	8,284
Foreign	127	4,451	254
	(6,283)	52,054	72,927
Deferred:			
Income taxes -			
Federal	105,528	62,618	(147,607)
State	13,157	4,147	(22,370)
Investment tax credit - net	240	(180)	213
	118,925	66,585	(169,764)
Change in uncertain tax benefits	(1,048)	3,230	562
Change in accrued interest	(1,320)	661	183
Total income tax expense (benefit)	$ 110,274	$ 122,530	$ (96,092)

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

	2011	2010
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 119,189	$ 114,427
Accrued pension costs	95,260	82,085
Asset retirement obligations	26,380	24,391
Legal and environmental contingencies	21,788	13,622
Compensation-related	16,241	17,261
Other	41,055	40,307
Total deferred tax assets	319,913	292,093
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	715,482	679,809
Basis differences on natural gas and oil producing properties	210,146	152,455
Regulatory matters	84,963	64,017
Intangible asset amortization	14,307	14,843
Other	23,774	20,348
Total deferred tax liabilities	1,048,672	931,472
Net deferred income tax liability	$ (728,759)	$ (639,379)

As of December 31, 2011 and 2010, no valuation allowance has been recorded associated with the previously identified deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2010, to December 31, 2011, to deferred income tax expense:

		2011
		(In thousands)
Change in net deferred income tax liability from the preceding table	**$**	**89,380**
Deferred taxes associated with other comprehensive loss		**9,678**
Deferred taxes associated with discontinued operations		**8,090**
Other		**11,777**
Deferred income tax expense for the period	**$**	**118,925**

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,		**2011**			2010			2009	
		Amount	%		Amount	%		Amount	%
					(Dollars in thousands)				
Computed tax at federal statutory rate	**$**	**117,679**	**35.0**	$	128,293	35.0	$	(76,778)	35.0
Increases (reductions) resulting from:									
State income taxes, net of federal income tax benefit (expense)		**10,653**	**3.2**		10,210	2.8		(7,280)	3.3
Resolution of tax matters and uncertain tax positions		**(3,906)**	**(1.2)**		667	.2		881	(.4)
Federal renewable energy credit		**(3,485)**	**(1.0)**		(2,185)	(.6)		(1,452)	.7
Depletion allowance		**(3,266)**	**(1.0)**		(2,810)	(.8)		(2,320)	1.0
Deductible K-Plan dividends		**(2,282)**	**(.7)**		(2,309)	(.6)		(2,369)	1.1
Foreign operations		**(391)**	**(.1)**		(588)	(.2)		(1,148)	.5
Domestic production activities deduction		**—**	**—**		—	—		(856)	.4
Other		**(4,728)**	**(1.4)**		(8,748)	(2.4)		(4,770)	2.2
Total income tax expense (benefit)	**$**	**110,274**	**32.8**	$	122,530	33.4	$	(96,092)	43.8

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.

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $6.9 million at December 31, 2011. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2011, was approximately $1.6 million.

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

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

		2011		2010		2009
				(In thousands)		
Balance at beginning of year	**$**	**9,378**	$	6,148	$	5,586
Additions for tax positions of prior years		**4,172**		3,230		562
Settlements		**(2,344)**		—		—
Balance at end of year	**$**	**11,206**	$	9,378	$	6,148

Included in the balance of unrecognized tax benefits at December 31, 2011 and 2010, were $6.6 million and $3.8 million, respectively, of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $6.0 million, including approximately $1.4 million for the payment of interest and penalties at December 31, 2011, and was $7.1 million, including approximately $1.5 million for the payment of interest and penalties at December 31, 2010.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2011, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2011, 2010 and 2009, the Company recognized approximately $780,000, $2.0 million and $190,000, respectively, in interest expense. Penalties were not material in 2011, 2010 and 2009. The Company recognized interest income of approximately $1.9 million, $20,000 and $165,000 for the years ended December 31, 2011, 2010 and 2009, respectively. The Company had accrued liabilities of approximately $970,000 and $2.3 million at December 31, 2011 and 2010, 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 ECTE.

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

The pipeline and energy services segment provides natural gas transportation, underground storage 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 other energy-related services.

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

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

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

	2011	2010	2009
		(In thousands)	
External operating revenues:			
Electric	**$ 225,468**	$ 211,544	$ 196,171
Natural gas distribution	**907,400**	892,708	1,072,776
Pipeline and energy services	**210,846**	254,776	235,322
	1,343,714	1,359,028	1,504,269
Exploration and production	**359,873**	318,570	338,425
Construction materials and contracting	**1,509,538**	1,445,148	1,515,122
Construction services	**834,918**	786,802	818,685
Other	**2,449**	147	—
	2,706,778	2,550,667	2,672,232
Total external operating revenues	**$ 4,050,492**	$ 3,909,695	$ 4,176,501

	2011	2010	2009
		(In thousands)	
Intersegment operating revenues:			
Electric	**$ —**	$ —	$ —
Natural gas distribution	—	—	—
Pipeline and energy services	**67,497**	75,033	72,505
Exploration and production	**93,713**	115,784	101,230
Construction materials and contracting	**472**	—	—
Construction services	**19,471**	2,298	379
Other	**8,997**	7,580	9,487
Intersegment eliminations	**(190,150)**	(200,695)	(183,601)
Total intersegment operating revenues	**$ —**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	**$ 32,177**	$ 27,274	$ 24,637
Natural gas distribution	**44,641**	43,044	42,723
Pipeline and energy services	**25,502**	26,001	25,581
Exploration and production	**142,645**	130,455	129,922
Construction materials and contracting	**85,459**	88,331	93,615
Construction services	**11,399**	12,147	12,760
Other	**1,572**	1,591	1,304
Total depreciation, depletion and amortization	**$ 343,395**	$ 328,843	$ 330,542
Interest expense:			
Electric	**$ 13,745**	$ 12,216	$ 9,577
Natural gas distribution	**29,444**	28,996	30,656
Pipeline and energy services	**10,516**	9,064	8,896
Exploration and production	**7,445**	8,580	10,621
Construction materials and contracting	**16,241**	19,859	20,495
Construction services	**4,473**	4,411	4,490
Other	**—**	47	43
Intersegment eliminations	**(510)**	(162)	(679)
Total interest expense	**$ 81,354**	$ 83,011	$ 84,099
Income taxes:			
Electric	**$ 7,242**	$ 11,187	$ 8,205
Natural gas distribution	**16,931**	12,171	16,331
Pipeline and energy services	**12,912**	13,933	22,982
Exploration and production	**46,298**	49,034	(187,000)
Construction materials and contracting	**11,227**	13,822	25,940
Construction services	**13,426**	11,456	15,189
Other	**2,238**	10,927	2,261
Total income taxes	**$ 110,274**	$ 122,530	$ (96,092)
Earnings (loss) on common stock:			

Electric	**$ 29,258**	$ 28,908	$ 24,099
Natural gas distribution	**38,398**	36,944	30,796
Pipeline and energy services	**23,082**	23,208	37,845
Exploration and production	**80,282**	85,638	(296,730)
Construction materials and contracting	**26,430**	29,609	47,085
Construction services	**21,627**	17,982	25,589
Other	**6,190**	21,046	7,357
Earnings (loss) on common stock before loss from discontinued operations	**225,267**	243,335	(123,959)
Loss from discontinued operations, net of tax*	**(12,926)**	(3,361)	—
Total earnings (loss) on common stock	**$ 212,341**	$ 239,974	$ (123,959)

	2011	2010	2009
		(In thousands)	
Capital expenditures:			
Electric	**$ 52,072**	$ 85,787	$ 115,240
Natural gas distribution	**70,624**	75,365	43,820
Pipeline and energy services	**45,556**	14,255	70,168
Exploration and production	**272,855**	355,845	183,140
Construction materials and contracting	**52,303**	25,724	26,313
Construction services	**9,711**	14,849	12,814
Other	**18,759**	2,182	3,196
Net proceeds from sale or disposition of property and other	**(40,857)**	(78,761)	(26,679)
Total net capital expenditures	**$ 481,023**	$ 495,246	$ 428,012
Assets:			
Electric**	**$ 672,940**	$ 643,636	$ 569,666
Natural gas distribution**	**1,679,091**	1,632,012	1,588,144
Pipeline and energy services	**526,797**	523,075	538,230
Exploration and production	**1,481,556**	1,342,808	1,137,628
Construction materials and contracting	**1,374,026**	1,382,836	1,449,469
Construction services	**418,519**	387,627	328,895
Other***	**403,196**	391,555	378,920
Total assets	**$ 6,556,125**	$ 6,303,549	$ 5,990,952
Property, plant and equipment:			
Electric**	**$ 1,068,524**	$ 1,027,034	$ 941,791
Natural gas distribution**	**1,568,866**	1,508,845	1,456,208
Pipeline and energy services	**719,291**	683,807	675,199
Exploration and production	**2,615,146**	2,356,938	2,028,794
Construction materials and contracting	**1,499,852**	1,486,375	1,514,989
Construction services	**124,796**	122,940	116,236
Other	**49,747**	32,564	33,365
Less accumulated depreciation, depletion and amortization	**3,361,208**	3,103,323	2,872,465
Net property, plant and equipment	**$ 4,285,014**	$ 4,115,180	$ 3,894,117

* Reflected in the Other category.
** Includes allocations of common utility property.
*** Includes assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).
Note: The results reflect a $620.0 million ($384.4 million after tax) noncash write-down of natural gas and oil properties in 2009.

Excluding the natural gas gathering arbitration charge of $16.5 million (after tax) in 2010, as discussed in Note 19, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from exploration and production, construction materials and contracting, construction services and other are all from nonregulated operations.

Capital expenditures for 2011, 2010 and 2009 include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions. The net noncash transactions were $24.0 million in 2011, $17.5 million in 2010 and immaterial in 2009.

Note 16 - Employee Benefit Plans

Pension and other postretirement benefit plans

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

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011, all benefit and service accruals for an additional union plan were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

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

Changes in benefit obligation and plan assets for the years ended December 31, 2011 and 2010, and amounts recognized in the Consolidated Balance Sheets at December 31, 2011 and 2010, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
		(In thousands)		
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 388,589**	$ 352,915	**$ 91,286**	$ 88,151
Service cost	**2,252**	2,889	**1,443**	1,357
Interest cost	**19,500**	19,761	**4,700**	4,817
Plan participants' contributions	**—**	—	**2,644**	2,500
Amendments	**—**	353	**—**	121
Actuarial loss	**62,722**	34,687	**17,940**	3,228
Curtailment gain	**(13,939)**	—	**—**	—
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Benefit obligation at end of year	**435,618**	388,589	**110,689**	91,286
Change in net plan assets:				
Fair value of plan assets at beginning of year	**277,598**	255,327	**70,610**	66,984
Actual gain (loss) on plan assets	**(4,718)**	37,853	**(872)**	7,278
Employer contribution	**28,626**	6,434	**3,027**	2,736
Plan participants' contributions	**—**	—	**2,644**	2,500
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Fair value of net plan assets at end of year	**278,000**	277,598	**68,085**	70,610
Funded status - under	**$ (157,618)**	$ (110,991)	**$ (42,604)**	$ (20,676)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	**$ —**	$ —	**$ (550)**	$ (525)
Other liabilities (noncurrent)	**(157,618)**	(110,991)	**(42,054)**	(20,151)
Net amount recognized	**$ (157,618)**	$ (110,991)	**$ (42,604)**	$ (20,676)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 189,494**	$ 117,840	**$ 43,861**	$ 20,751
Prior service cost (credit)	**(632)**	631	**(8,615)**	(11,292)
Transition obligation	**—**	—	**2,128**	4,253
Total	**$ 188,862**	$ 118,471	**$ 37,374**	$ 13,712

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 are amortized on a straight-line basis over the expected average remaining service lives of active participants for non-frozen plans and over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation is amortized over a 20-year period ending 2012.

The accumulated benefit obligation for the defined benefit pension plans reflected previously was $435.6 million and $374.5 million at December 31, 2011 and 2010, 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:

	2011	2010
	(In thousands)	
Projected benefit obligation	**$ 435,618**	$ 388,589
Accumulated benefit obligation	**$ 435,618**	$ 374,538
Fair value of plan assets	**$ 278,000**	$ 277,598

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		
	2011	2010	2009	**2011**	2010	2009
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	**$ 2,252**	$ 2,889	$ 8,127	**$ 1,443**	$ 1,357	$ 2,206
Interest cost	**19,500**	19,761	21,919	**4,700**	4,817	5,465
Expected return on assets	**(22,809)**	(23,643)	(25,062)	**(5,051)**	(5,512)	(5,471)
Amortization of prior service cost (credit)	**45**	152	605	**(2,677)**	(3,303)	(2,756)
Recognized net actuarial loss	**4,656**	2,622	2,096	**753**	845	970
Curtailment loss	**1,218**	—	1,650	**—**	—	—
Amortization of net transition obligation	**—**	—	—	**2,125**	2,125	2,125
Net periodic benefit cost, including amount capitalized	**4,862**	1,781	9,335	**1,293**	329	2,539
Less amount capitalized	**1,196**	791	1,127	**(50)**	(92)	330
Net periodic benefit cost	**3,666**	990	8,208	**1,343**	421	2,209
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**76,310**	20,477	(29,000)	**23,863**	1,462	(2,314)
Prior service cost (credit)	**—**	353	—	**—**	121	(9,321)
Amortization of actuarial loss	**(4,656)**	(2,622)	(2,096)	**(753)**	(845)	(970)
Amortization of prior service (cost) credit	**(1,263)**	(152)	(2,255)	**2,677**	3,303	2,756
Amortization of net transition obligation	**—**	—	—	**(2,125)**	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	**70,391**	18,056	(33,351)	**23,662**	1,916	(11,974)

Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	**$ 74,057**	$ 19,046	$ (25,143)	**$ 25,005**	$ 2,337	$ (9,765)

The estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $7.6 million and $85,000, 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 2012 are $1.9 million, $1.1 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	
	2011	2010	**2011**	2010
Discount rate	**4.16%**	5.26%	**4.13%**	5.21%
Expected return on plan assets	**7.75%**	7.75%	**6.75%**	6.75%
Rate of compensation increase	**N/A**	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	
	2011	2010	**2011**	2010
Discount rate	**5.26%**	5.75%	**5.21%**	5.75%
Expected return on plan assets	**7.75%**	8.25%	**6.75%**	7.25%
Rate of compensation increase	**% / 4.00N/A ***	4.00%	**4.00%**	4.00%

* Effective June 30, 2011, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.

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

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

	2011	2010
Health care trend rate assumed for next year	**6.0% - 8.0%**	6.0% - 8.5%
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, 2011:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 171	$ (822)
Effect on postretirement benefit obligation	$ 3,175	$ (10,946)

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 futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

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

	Fair Value Measurements at December 31, 2011, 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, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 2,256	$ 17,534	$ —	$ 19,790
Equity securities:				
U.S. companies	99,315	—	—	99,315
International companies	35,353	—	—	35,353
Collective and mutual funds (a)	43,214	15,541	—	58,755
Corporate bonds	—	23,579	289	23,868
Mortgage-backed securities	—	22,987	—	22,987
Municipal bonds	—	9,290	—	9,290
U.S. Treasury securities	—	8,642	—	8,642
Total assets measured at fair value	$ 180,138	$ 97,573	$ 289	$ 278,000

(a) Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.

	Fair Value Measurements at December 31, 2010, 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, 2010
	(In thousands)			
Assets:				
Cash equivalents	$ 4,663	$ 8,699	$ —	$ 13,362
Equity securities:				
U.S. companies	102,944	—	—	102,944
International companies	40,017	—	—	40,017
Collective and mutual funds (a)	45,410	17,701	—	63,111
Collateral held on loaned securities (b)	—	23,148	694	23,842
Corporate bonds	—	23,014	—	23,014
Mortgage-backed securities	—	19,478	—	19,478
U.S. Treasury securities	—	9,239	—	9,239
Municipal bonds	—	8,285	—	8,285
Total assets measured at fair value	193,034	109,564	694	303,292
Liabilities:				
Obligation for collateral received	25,694	—	—	25,694
Net assets measured at fair value	$ 167,340	$ 109,564	$ 694	$ 277,598

(a) Collective and mutual funds invest approximately 28 percent in common stock of mid-cap U.S. companies, 24 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 11 percent in mortgage-backed securities, 10 percent in corporate bonds, 8 percent in foreign fixed-income investments and 6 percent in common stock of small-cap U.S. companies.

(b) This class includes collateral held at December 31, 2010, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, mutual funds and commercial paper.

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, 2011:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
	(In thousands)		
Balance at beginning of year	$ —	$ 694	$ 694
Total realized/unrealized losses	(2)	(259)	(261)
Purchases, issuances and settlements (net)	291	(435)	(144)
Balance at end of year	$ 289	$ —	$ 289

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, 2010:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Collateral Held on Loaned Securities
	(In thousands)
Balance at beginning of year	$ 937
Total realized/unrealized losses	189
Purchases, issuances and settlements (net)	(432)
Balance at end of year	$ 694

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

	Fair Value Measurements at December 31, 2011, 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, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 59	$ 1,836	$ —	$ 1,895
Equity securities:				
U.S. companies	2,098	—	—	2,098
International companies	262	—	—	262
Insurance investment contract*	—	63,830	—	63,830
Total assets measured at fair value	$ 2,419	$ 65,666	$ —	$ 68,085

* The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.

	Fair Value Measurements at December 31, 2010, 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, 2010
	(In thousands)			
Assets:				
Cash equivalents	$ 53	$ 1,274	$ —	$ 1,327
Equity securities:				
U.S. companies	2,791	—	—	2,791
International companies	353	—	—	353
Insurance investment contract*	—	66,139	—	66,139
Total assets measured at fair value	$ 3,197	$ 67,413	$ —	$ 70,610

* The insurance investment contract invests approximately 53 percent in common stock of large-cap U.S. companies, 21 percent in corporate bonds, 12 percent in mortgage-backed securities and 14 percent in other investments.

The Company expects to contribute approximately $20.2 million to its defined benefit pension plans and approximately $4.0 million to its postretirement benefit plans in 2012.

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2012	$ 22,426	$ 6,892	$ 618
2013	22,811	7,062	656
2014	23,082	7,188	694
2015	23,508	7,298	730
2016	23,893	7,371	766
2017 - 2021	127,895	37,682	4,322

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of $76.9 million and $77.5 million at December 31, 2011 and 2010, respectively, consisting of equity securities of $38.4 million and $39.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $31.8 million and $30.7 million, respectively, and other investments of $6.7 million and $7.3 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $8.1 million, $7.8 million and $8.8 million in 2011, 2010 and 2009, respectively. The total projected benefit obligation for these plans was $113.8 million and $99.4 million at December 31, 2011 and 2010, respectively. The accumulated benefit obligation for these plans was $105.7 million and $93.2 million at December 31, 2011 and 2010, respectively. A weighted average discount rate of 4 percent and 5.11 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4 percent at December 31, 2011 and 2010, were used to determine benefit obligations. A discount rate of 5.11 percent and 5.75 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4 percent at December 31, 2011 and 2010, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $5.2 million in 2012; $5.9 million in 2013; $5.8 million in 2014; $6.9 million in 2015; $6.8 million in 2016 and $38.3 million for the years 2017 through 2021.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $27.1 million in 2011, $24.4 million in 2010 and $20.5 million in 2009.

Multiemployer plans

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

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

The Company's participation in these plans for the annual period ended December 31, 2011, is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2011 and 2010 is for the plan's year-end at December 31, 2010, and December 31, 2009, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at

least 80 percent funded. From 2009 to 2010 and 2010 to 2011, contributions by the Company to multiemployer defined benefit pension plans decreased as a result of a reduction in covered employees corresponding to a decline in overall business.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status		FIP/RP Status Pending/ Implemented	Contributions			Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
		2011	2010		**2011**	2010	2009		
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green	Green	No	$ **2,700**	$ 1,933	$ 1,627	No	12/31/2012
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**1,469**	1,277	594	No	*
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2011	Red as of 6/30/2010	Implemented	**1,331**	1,569	1,197	No	*
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2011	Red as of 2/28/2010	Implemented	**722**	781	641	No	8/31/2012
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2011	Yellow as of 5/31/2010	Implemented	**628**	413	325	No	6/30/2012*
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**776**	679	469	No	*
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**4,841**	4,826	5,462	No	5/31/2014*
OE Pension Trust Fund	94-6090764-001	Yellow	Yellow	Implemented	**1,367**	1,035	1,061	No	3/31/2016*
Other funds					**15,324**	17,763	21,103		
Total contributions					$ **29,158**	$ 30,276	$ 32,479		

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

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

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Defined Benefit Pension Plan of AGC-IUOE Local 701 Pension Trust Fund	2010 and 2009
Edison Pension Plan	2010 and 2009
Eighth District Electrical Pension Fund	2010 and 2009
IBEW Local 38 Pension Plan	2010 and 2009
IBEW Local No. 82 Pension Plan	2010 and 2009
IBEW Local Union No. 357 Pension Plan A	2010 and 2009
IBEW Local 648 Pension Plan	2010 and 2009
Idaho Plumbers and Pipefitters Pension Plan	2010 and 2009
Laborers AGC Pension Trust of Montana	2009
Local Union No. 124 IBEW Pension Trust Fund	2010 and 2009
Local Union 212 IBEW Pension Trust Fund	2010 and 2009
Minnesota Teamsters Constr Division Pension Fund	2010 and 2009
Operating Engineers Local 800 and Wyoming Contractors Association, Inc. Pension Plan for Wyoming	2010 and 2009
Plumbers & Pipefitters Local 162 Pension Fund	2010 and 2009
Southwest Marine Pension Trust	2009

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

$24.7 million and $28.9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Amounts contributed in 2011, 2010 and 2009 to defined contribution multiemployer plans were $15.3 million, $15.4 million and $16.4 million, respectively.

Note 17 - Jointly Owned Facilities

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

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses 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:

	2011	2010
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 63,715**	$ 60,404
Less accumulated depreciation	**42,475**	41,136
	$ 21,240	$ 19,268
Coyote Station:		
Utility plant in service	**$ 131,719**	$ 131,395
Less accumulated depreciation	**86,788**	84,710
	$ 44,931	$ 46,685
Wygen III:*		
Utility plant in service	**$ 63,300**	$ 63,215
Less accumulated depreciation	**2,106**	838
	$ 61,194	$ 62,377

* Began commercial operation on April 1, 2010.

Note 18 - Regulatory Matters and Revenues Subject to Refund

On May 20, 2011, Montana-Dakota filed an application with the NDPSC requesting advance determination of prudence that the addition of the air quality control system at the Big Stone Station, to comply with the Clean Air Act and the South Dakota Regional Haze Implementation Plan, is reasonable and prudent. A hearing was held on November 29, 2011. On January 9, 2012, Montana-Dakota, Otter Tail Corporation and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the air quality control system is prudent. An order is expected in the first quarter of 2012.

On July 7, 2011, Montana-Dakota filed for an advance determination of prudence with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities projected to be in service in 2015. The turbine will be located on company-owned property that is adjacent to Montana-Dakota's Heskett Generating Station near Mandan, North Dakota, and would be used to meet the capacity requirements of Montana-Dakota's integrated electric system service customers. The capacity will be a partial replacement for third party contract capacity expiring in 2015. Project cost is estimated to be $85.6 million. A hearing was held on January 10, 2012. On January 18, 2012, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the natural gas turbine is prudent and a certificate of need should be approved. An order is expected in the first quarter of 2012.

On November 15, 2011, the MNPUC issued a Notice of Investigation; Opportunity to Respond and Comment to investigate whether Great Plains' rates are unreasonable and whether Great Plains should be ordered to initiate a general rate proceeding as Great Plains has earned in excess of its authorized return and the excess earnings are likely to continue into the future. On December 2, 2011, Great Plains responded to the MNPUC's Notice. On January 30, 2012, the MNPUC issued an order that found that the reasonableness of Great Plains' rates had not been resolved to the MNPUC's satisfaction and requires Great Plains to initiate a rate proceeding within 180 days of the order. In addition, the MNPUC encouraged Great Plains, the Minnesota Department of Commerce and any other interested parties to enter into settlement discussions with the requirement that the interested parties file a report on the status of settlement discussions within 60 days of the order.

Note 19 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. The Company had accrued liabilities of $64.1 million and $45.3 million for contingencies related to litigation and environmental matters as of December 31, 2011 and 2010, respectively, which includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation, which letter of credit expired in November 2010. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand sought compensatory damages of $149.7 million. In June 2010, CEM and Bicent made a demand on Centennial Resources for indemnification under the 2007 purchase and sale agreement for indemnifiable losses, including defense fees and costs arising from LPP's arbitration demand and related to Centennial Resources' ownership of CEM prior to its sale to Bicent. Centennial and Centennial Resources filed a complaint with the Supreme Court of the State of New York in November 2010, against Bicent seeking damages for breach of contract and other relief including specific performance of the 2007 purchase and sale agreement allowing for Centennial Resources' participation in the arbitration proceeding and replacement of the letter of credit. On September 19, 2011, Bicent filed a counterclaim seeking damages against Centennial Resources related to Bicent's costs of defending the LPP arbitration demand which Bicent alleged were in excess of $14.0 million. The arbitration hearing on LPP's claim was held in the third quarter of 2011, and an arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award is recorded in discontinued operations on the Consolidated Statement of Income. The Company intends to vigorously defend against the claims of LPP and Bicent.

Construction Materials In 2009, LTM provided pavement work under a subcontract for reconstruction at the Klamath Falls Airport owned by the City of Klamath Falls, Oregon. In October 2010, the City of Klamath Falls filed a complaint in Oregon Circuit Court against the project's general contractor alleging the work performed by LTM is defective. The general contractor tendered the defense and indemnity of the claim to LTM and its insurance carrier. On January 18, 2011, the general contractor served a third party complaint against LTM seeking indemnity and contribution for damages imposed on the general contractor. LTM filed a fourth-party complaint seeking contribution and indemnity for damages imposed on LTM against the project engineer firm which prepared the specifications for the airport runway. LTM's insurance carrier accepted defense of the complaint against the general contractor and the third party complaint against LTM subject to reservation of its rights under the applicable insurance policy. Damages, including removal and replacement of the paved runway, were estimated by the plaintiff in its complaint as $6.0 million to $11.0 million. The Oregon Circuit Court granted a motion by LTM to dismiss certain of the plaintiff's claims relating to approximately $5.0 million of damages but allowed the plaintiff to amend its complaint. In its amended complaint, the plaintiff asserted new claims with estimated damages of $21.9 million plus interest and attorney fees. LTM and its insurers have been engaged in mediation and settlement discussions with the other parties to resolve this matter.

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

permit; however, the imposition of civil penalties is reasonably possible. The Company intends to resolve this matter through settlement or continuation of the Montana First Judicial District Court litigation.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel Bitter Creek to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of Bitter Creek's pipeline gathering systems in Montana. Bitter Creek resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered Bitter Creek into arbitration. An arbitration hearing was held in August 2010. In October 2010, Bitter Creek was notified that the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, Bitter Creek, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010, which is recorded in operation and maintenance expense on the Consolidated Statement of Income. On April 20, 2011, the Colorado State District Court entered an order denying a motion by Bitter Creek to vacate the arbitration award and granting a motion by SourceGas to confirm the arbitration award as a court judgment. The Colorado State District Court also awarded $293,000 to SourceGas for legal fees and expenses. Bitter Creek filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals on April 28, 2011.

In a related matter, Omimex filed a complaint against Bitter Creek in Montana Seventeenth Judicial District Court in July 2010 alleging Bitter Creek breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging Bitter Creek breached obligations to operate its gathering system as a common carrier under United States and Montana law. Bitter Creek removed the action to the United States District Court for the District of Montana. Expert reports submitted by Omimex contend its damages as a result of the increased operating pressures are $18.8 million to $22.6 million. The Company believes the claims asserted by Omimex are without merit and intends to vigorously defend against the claims.

The Company also is involved in other legal actions in the ordinary course of its business. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above and other legal proceedings will not have a material effect upon the Company's financial position, results of operations or cash flows.

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

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

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

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at

manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has reserved $1.2 million for remediation of this site.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In September 2011, the EPA issued notice of a proposal to add the site to the National Priorities List. Cascade has met with the EPA to discuss a possible settlement agreement and administrative order for performance of a remedial investigation and feasibility study of the site with the intent of reaching consensus on the scope and schedule for the remedial investigation and feasibility study. Cascade has reserved $6.4 million for remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

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

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

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, 2011, were $27.8 million in 2012, $24.3 million in 2013, $16.4 million in 2014, $8.6 million in 2015, $5.8 million in 2016 and $35.9 million thereafter. Rent expense was $40.7 million, $38.7 million and $43.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage, service and construction materials supply contracts. These commitments range from one to 49 years. The commitments under these contracts as of December 31, 2011, were $478.0 million in 2012, $215.9 million in 2013, $135.8 million in 2014, $71.1 million in 2015, $36.7 million in 2016 and $287.0 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, 2011, 2010 and 2009, were $626.3 million, $611.7 million and $723.1 million.

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

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

WBI Holdings has guaranteed certain of Fidelity's natural gas and oil swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil swap and collar agreements as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil swap and collar agreements at December 31, 2011, expire in the years ranging from 2012 to 2013; 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. The amount outstanding by Fidelity was $4.3 million and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At December 31, 2011, the fixed maximum amounts guaranteed under these agreements aggregated $85.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $42.0 million in 2012; $34.4 million in 2013; $1.3 million in 2014; $100,000 in 2015; $100,000 in 2016; $800,000 in 2018; $300,000 in 2019; $2.6 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 $500,000 and was reflected on the Consolidated Balance Sheet at December 31, 2011. 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, natural gas transportation agreements and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2011, the fixed maximum amounts guaranteed under these letters of credit, aggregated $27.4 million. In 2012 and 2013, $24.1 million and $3.3 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at December 31, 2011.

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, 2011, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.2 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2011, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2011.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries, as well as an arbitration award. 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, 2011, approximately $463 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2011 and 2010:

	First Quarter	Second Quarter	Third Quarter *	Fourth Quarter **
	(In thousands, except per share amounts)			
2011				
Operating revenues	**$ 901,805**	**$ 930,757**	**$ 1,152,181**	**$ 1,065,749**
Operating expenses	**823,739**	**848,454**	**1,032,760**	**939,172**
Operating income	**78,066**	**82,303**	**119,421**	**126,577**
Income from continuing operations	**42,529**	**45,235**	**64,100**	**74,088**
Income (loss) from discontinued operations, net of tax	**448**	**(168)**	**(126)**	**(13,080)**
Net income	**42,977**	**45,067**	**63,974**	**61,008**
Earnings per common share - basic:				
Earnings before discontinued operations	**.22**	**.24**	**.34**	**.39**
Discontinued operations, net of tax	**.01**	**—**	**—**	**(.07)**
Earnings per common share - basic	**.23**	**.24**	**.34**	**.32**
Earnings per common share - diluted:				
Earnings before discontinued operations	**.22**	**.24**	**.34**	**.39**
Discontinued operations, net of tax	**.01**	**—**	**—**	**(.07)**
Earnings per common share - diluted	**.23**	**.24**	**.34**	**.32**
Weighted average common shares outstanding:				
Basic	**188,671**	**188,794**	**188,794**	**188,794**
Diluted	**188,815**	**188,968**	**188,797**	**188,932**
2010				
Operating revenues	$ 834,777	$ 906,444	$ 1,125,923	$ 1,042,551
Operating expenses	751,848	817,782	1,016,961	912,377
Operating income	82,929	88,662	108,962	130,174
Income from continuing operations	41,772	48,938	61,010	92,300
Loss from discontinued operations, net of tax	—	—	—	(3,361)
Net income	41,772	48,938	61,010	88,939
Earnings per common share - basic:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share - basic	.22	.26	.32	.47
Earnings per common share - diluted:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share - diluted	.22	.26	.32	.47
Weighted average common shares outstanding:				
Basic	187,963	188,129	188,170	188,281
Diluted	188,220	188,267	188,338	188,374

* 2010 reflects a natural gas gathering arbitration charge of $16.5 million (after tax). For more information, see Note 19.

** 2011 reflects an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract. For more information, see Note 19. 2010 reflects a $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines. For more information, see Note 4.

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

Exploration and Production Activities (Unaudited)

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

The information that follows includes Fidelity's proportionate share of all its 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:

	2011	2010	2009
		(In thousands)	
Subject to amortization	**$ 2,345,114**	$ 2,138,565	$ 1,815,380
Not subject to amortization	**232,462**	182,402	178,214
Total capitalized costs	**2,577,576**	2,320,967	1,993,594
Less accumulated depreciation, depletion and amortization	**1,229,654**	1,093,723	969,630
Net capitalized costs	**$ 1,347,922**	$ 1,227,244	$ 1,023,964

Note: Net capitalized costs 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,	**2011** *	2010 *	2009 *
		(In thousands)	
Acquisitions:			
Proved properties	**$ 3,999**	$ 89,733	$ 3,879
Unproved properties	**63,354**	92,100	8,771
Exploration	**41,775**	33,226	33,123
Development	**161,647**	139,733	135,202
Total capital expenditures	**$ 270,775**	$ 354,792	$ 180,975

* Excludes net additions/(reductions) to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of natural gas and oil wells, as discussed in Note 10, of $(1.8) million, $11.1 million and $2.0 million for the years ended December 31, 2011, 2010 and 2009, 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,	**2011**	2010	2009
		(In thousands)	
Revenues:			
Sales to affiliates	**$ 93,713**	$ 115,784	$ 101,230
Sales to external customers	**359,873**	318,565	338,425
Production costs	**140,606**	127,403	123,148
Depreciation, depletion and amortization*	**139,539**	127,266	126,278
Write-down of natural gas and oil properties	—	—	620,000
Pretax income	**173,441**	179,680	(429,771)
Income tax expense	**63,655**	66,293	(164,216)
Results of operations for producing activities	**$ 109,786**	$ 113,387	$ (265,555)

* Includes accretion of discount for asset retirement obligations of $3.6 million, $3.2 million and $2.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, as discussed in Note 10.

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The reserve estimates as of December 31, 2011, 2010 and 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. Other factors used in the reserve estimates are 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 are prepared by internal engineers assigned to an asset team by geographic area. Senior management reviews and approves the reserve estimates to ensure they are materially accurate. In addition, the Company engaged Ryder Scott, an independent third party, to audit its proved reserve quantity estimates.

Estimates of economically recoverable 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.

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

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	448,397	32,867	645,596
Production	(45,598)	(3,500)	(66,596)
Extensions and discoveries	28,221	6,138	65,049
Improved recovery	—	—	—
Purchases of proved reserves	54	239	1,486
Sales of proved reserves	—	—	—
Revisions of previous estimates	(51,247)	(1,397)	(59,627)
Balance at end of year	379,827	34,347	585,908

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

- Extensions and discoveries of 65.0 Bcfe primarily due to drilling activity at the Company's Bakken and Big Horn properties
- Revisions of previous estimates of (59.6) Bcfe, largely the result of a reduction in PUD reserves of 53.6 Bcfe resulting principally in the Company's Bowdoin, Baker, Coalbed, East Texas and Big Horn Basin properties. The remaining negative revisions were a reduction in PDP natural gas reserves.

The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2010, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	448,425	34,216	653,724
Production	(50,391)	(3,262)	(69,963)
Extensions and discoveries	36,191	3,389	56,523
Improved recovery	—	—	—
Purchases of proved reserves	55,119	979	60,991
Sales of proved reserves	(92)	(18)	(202)
Revisions of previous estimates	(40,855)	(2,437)	(55,477)
Balance at end of year	448,397	32,867	645,596

Significant changes in proved reserves for the year ended December 31, 2010, include:

- Extensions and discoveries of 56.5 Bcfe primarily due to drilling activity at the Company's Bakken, Baker, Bowdoin and east Texas properties

- Purchases of proved reserves of 61.0 Bcfe as a result of the Company's acquisition of natural gas properties in the Green River Basin in Wyoming, as discussed in Note 2
- Revisions of previous estimates of (55.5) Bcfe largely the result of negative performance revisions resulting primarily from new information gained from production history and developmental drilling activity in the Company's Bowdoin, south Texas, Baker and east Texas properties and removal of PUD reserves due to the five-year limitation rule, partially offset by positive revisions due to increased natural gas and oil prices

The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2009, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	604,282	34,348	810,371
Production	(56,632)	(3,111)	(75,299)
Extensions and discoveries	26,882	2,569	42,297
Improved recovery	—	—	—
Purchases of proved reserves	—	—	—
Sales of proved reserves	(22)	(248)	(1,510)
Revisions of previous estimates	(126,085)	658	(122,135)
Balance at end of year	448,425	34,216	653,724

Significant changes in proved reserves for the year ended December 31, 2009, include:

- Extensions and discoveries of 42.3 Bcfe primarily due to drilling activity at the Company's Bowdoin, Bakken, Baker and east Texas properties
- Revisions of previous estimates of (122.1) Bcfe largely the result of negative revisions resulting from decreased natural gas and oil prices and negative performance revisions resulting primarily from new information gained from production history and developmental drilling activity in the Company's east Texas and south Texas properties

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

	2011	2010	2009
Proved developed reserves:			
Natural Gas (MMcf)	**303,495**	334,911	321,561
Oil (MBbls)	**28,878**	26,586	26,794
Total (MMcfe)	**476,763**	494,426	482,329
PUD reserves:			
Natural Gas (MMcf)	**76,332**	113,486	126,864
Oil (MBbls)	**5,469**	6,281	7,422
Total (MMcfe)	**109,145**	151,170	171,395
Total proved reserves:			
Natural Gas (MMcf)	**379,827**	448,397	448,425
Oil (MBbls)	**34,347**	32,867	34,216
Total (MMcfe)	**585,908**	645,596	653,724

As of December 31, 2011, the Company had 109.1 Bcfe of PUD reserves, which is a decrease of 42.0 Bcfe from December 31, 2010. The decrease relates to the Company converting 27.1 Bcfe of its December 31, 2010, PUD reserves into proved developed reserves in 2011, requiring $62.9 million of drilling and completion capital and 53.6 Bcfe of negative revisions applied to PUD locations primarily in the Company's natural gas properties. These changes were partially offset by 38.7 Bcfe of new PUD reserves primarily in the Company's oil properties. At December 31, 2011, the Company did not have any PUD locations that remained undeveloped for five years or more. Future development costs estimated to be spent in each of the next three years to develop PUD reserves as of December 31, 2011, are $109.3 million in 2012, $47.8 million in 2013 and $13.7 million in 2014.

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:

	2011	2010	2009
		(In thousands)	
Future cash inflows	$ **4,188,000**	$ 3,790,700	$ 2,991,200
Future production costs	**1,560,300**	1,393,000	1,095,600
Future development costs	**285,300**	312,500	315,000
Future net cash flows before income taxes	**2,342,400**	2,085,200	1,580,600
Future income tax expense	**531,100**	432,800	291,000
Future net cash flows	**1,811,300**	1,652,400	1,289,600
10% annual discount for estimated timing of cash flows	**832,500**	756,300	630,800
Discounted future net cash flows relating to proved natural gas and oil reserves	$ **978,800**	$ 896,100	$ 658,800

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

	2011	2010	2009
		(In thousands)	
Beginning of year	$ **896,100**	$ 658,800	$ 969,800
Net revenues from production	**(301,500)**	(270,000)	(200,900)
Net change in sales prices and production costs related to future production	**82,300**	362,400	(364,800)
Extensions and discoveries, net of future production-related costs	**226,300**	130,500	70,500
Improved recovery, net of future production-related costs	**—**	—	—
Purchases of proved reserves, net of future production-related costs	**9,500**	99,800	—
Sales of proved reserves	**—**	(500)	(1,100)
Changes in estimated future development costs	**51,100**	34,100	43,600
Development costs incurred during the current year	**56,300**	43,100	46,400
Accretion of discount	**105,000**	76,500	115,900
Net change in income taxes	**(55,800)**	(103,300)	142,800
Revisions of previous estimates	**(92,900)**	(132,000)	(155,500)
Other	**2,400**	(3,300)	(7,900)
Net change	**82,700**	237,300	(311,000)
End of year	$ **978,800**	$ 896,100	$ 658,800

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 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) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in Internal Controls

No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2011, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

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

Attestation Report of the Registered Public Accounting Firm

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

Part III

Item 10. Directors, Executive Officers and Corporate Governance

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

Item 11. Executive Compensation

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

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

Equity Compensation Plan Information

The following table includes information as of December 31, 2011, 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)	768,904	(2)	$ 19.30	6,310,260	(3)(4)
Equity compensation plans not approved by stockholders	N/A		N/A	N/A	

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

(2) Includes 762,154 performance shares.

(3) In addition to being available for issuance upon exercise of options, 357,757 shares remain available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan in connection with grants of stock appreciation rights, restricted stock, performance units, performance shares or other equity-based awards. 5,686,144 shares under the Long-Term Performance-Based Incentive Plan remain available for future issuance in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.

(4) This amount also includes 266,359 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors are awarded shares equal in value to $110,000 annually. A non-employee director may acquire additional shares under the plan in lieu of receiving the cash portion of the director's retainer or fees.

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

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

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

Item 14. Principal Accountant Fees and Services

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

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

The following financial statement schedules are included in Part IV of this report.

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

Condensed Statements of Income

Years ended December 31,	2011	2010	2009
		(In thousands)	
Operating revenues	$ 518,268	$ 503,658	$ 514,519
Operating expenses	450,579	431,293	458,130
Operating income	67,689	72,365	56,389
Other income	2,710	5,734	6,588
Interest expense	18,660	16,664	13,996
Income before income taxes	51,739	61,435	48,981
Income taxes	10,476	17,983	13,279
Equity in earnings of subsidiaries	171,763	197,207	(158,976)
Net income	213,026	240,659	(123,274)
Dividends declared on preferred stocks	685	685	685
Earnings on common stock	$ 212,341	$ 239,974	$ (123,959)

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

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

December 31,	2011	2010
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 6,900	$ 6,275
Receivables, net	67,761	76,757
Accounts receivable from subsidiaries	28,734	27,837
Inventories	42,596	34,583
Deferred income taxes	2	—
Prepayments and other current assets	12,154	15,473
Total current assets	158,147	160,925
Investments	47,835	48,038
Investment in subsidiaries	2,402,891	2,336,133
Property, plant and equipment	1,453,089	1,388,128
Less accumulated depreciation, depletion and amortization	605,510	583,447
Net property, plant and equipment	847,579	804,681
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	166,732	119,081
Total deferred charges and other assets	171,544	123,893
Total assets	$ 3,627,996	$ 3,473,670
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings	$ —	$ 20,000
Long-term debt due within one year	107	107
Accounts payable	37,986	36,235
Accounts payable to subsidiaries	4,868	9,445
Taxes payable	18,304	8,104
Deferred income taxes	—	469
Dividends payable	31,794	30,773
Accrued compensation	10,173	11,540
Other accrued liabilities	27,064	26,002
Total current liabilities	130,296	142,675
Long-term debt	280,781	280,889
Deferred credits and other liabilities:		
Deferred income taxes	137,751	103,725
Other liabilities	303,601	253,579
Total deferred credits and other liabilities	441,352	357,304
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	15,000	15,000

Common stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 188,332,485 shares in 2011 and 188,901,379 shares in 2010	**189,332**	188,901
Other paid-in capital	**1,035,739**	1,026,349
Retained earnings	**1,586,123**	1,497,439
Accumulated other comprehensive loss	**(47,001)**	(31,261)
Treasury stock at cost - 538,921 shares	**(3,626)**	(3,626)
Total common stockholders' equity	**2,760,567**	2,677,802
Total stockholders' equity	**2,775,567**	2,692,802
Total liabilities and stockholders' equity	**$ 3,627,996**	$ 3,473,670

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

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

Years ended December 31,	2011	2010	2009
		(In thousands)	
Net cash provided by operating activities	**$ 217,514**	$ 185,887	$ 209,128
Investing activities:			
Capital expenditures	**(74,580)**	(114,045)	(120,352)
Net proceeds from sale or disposition of property and other	**720**	625	1,039
Investments in and advances to subsidiaries	**(5,701)**	(1,636)	—
Investments from and advances from subsidiaries	**—**	—	2,916
Disposition of investments in subsidiaries	**—**	—	20,000
Investments	**—**	(742)	(637)
Net cash used in investing activities	**(79,561)**	(115,798)	(97,034)
Financing activities:			
Issuance of short-term borrowings	**—**	20,000	—
Repayment of short-term borrowings	**(20,000)**	—	—
Issuance of long-term debt	**—**	—	50,000
Repayment of long-term debt	**(107)**	(107)	(85,104)
Proceeds from issuance of common stock	**5,744**	4,972	65,207
Dividends paid	**(123,323)**	(119,157)	(115,023)
Tax benefit on stock-based compensation	**358**	375	264
Net cash used in financing activities	**(137,328)**	(93,917)	(84,656)
Increase (decrease) in cash and cash equivalents	**625**	(23,828)	27,438
Cash and cash equivalents - beginning of year	**6,275**	30,103	2,665
Cash and cash equivalents - end of year	**$ 6,900**	$ 6,275	$ 30,103

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

Notes to Condensed Financial Statements

Note 1 - Summary of Significant Accounting Policies

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

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

Note 2 - Debt The Company has long-term debt obligations outstanding of $280.9 million at December 31, 2011, with annual maturities of $100,000 from 2012 to 2015, $50.0 million in 2016 and $230.5 million scheduled to mature in years after 2016.

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

Note 3 - Dividends The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $96.1 million, $96.4 million and $116.3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

MDU RESOURCES GROUP, INC.

Schedule II - Consolidated Valuation and Qualifying Accounts

For the years ended December 31, 2011, 2010 and 2009

		Additions			
Description	Balance at Beginning of Year	Charged to Costs and Expenses	Other *	Deductions **	Balance at End of Year
			(In thousands)		
Allowance for doubtful accounts:					
2011	**$ 15,284**	**$ 3,977**	**$ 2,112**	**$ 8,966**	**$ 12,407**
2010	16,649	5,044	2,300	8,709	15,284
2009	13,691	12,152	1,412	10,606	16,649

* 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 13, 2010, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*

3(b) Company Bylaws, as amended and restated, on November 17, 2011**

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

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

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

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

4(e) MDU Resources Group, Inc. Credit Agreement, dated May 26, 2011, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent**

4(f) 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(g) 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, filed as Exhibit 4(i) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

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

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

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

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

4(l)	Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*
4(m)	Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*
+10(a)	Supplemental Income Security Plan, as amended and restated November 12, 2009, filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(b) Directors' Compensation Policy, as amended May 12, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*

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

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

+10(e) Non-Employee Director Long-Term Incentive Compensation Plan, as amended November 12, 2009, filed as Exhibit 10(f) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(f) WBI Holdings, Inc. Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended November 11, 2009, filed as Exhibit 10(i) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(g) Knife River Corporation Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended November 16, 2009, filed as Exhibit 10(j) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(h) Long-Term Performance-Based Incentive Plan, as amended November 17, 2011**

+10(i) MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended November 15, 2007, and Rules and Regulations, as amended November 11, 2009, filed as Exhibit 10(l) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(j) Montana-Dakota Utilities Co. Executive Incentive Compensation Plan, as amended November 15, 2007, and Rules and Regulations, as amended November 11, 2009, filed as Exhibit 10(m) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(k) 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(l) MDU Resources Group, Inc. Executive Officers with Change of Control Employment Agreements Chart, as of December 31, 2010, filed as Exhibit 10(n) to Form 10-K for the year ended December 31, 2010, filed on February 23, 2011, in File No. 1-3480*

+10(m) 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(n) 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(o) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 15, 2011, filed as Exhibit 10.4 to Form 8-K dated February 15, 2011, filed on February 22, 2011, in File No. 1-3480*

+10(p) 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(q) Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan as amended February 22, 2011, filed as Exhibit 10.2 to Form 8-K dated February 15, 2011, filed on February 22, 2011, in File No. 1-3480*

+10(r) Agreement for Termination of Change of Control Employment Agreement, dated June 15, 2010, by and between MDU Resources Group, Inc. and Terry D. Hildestad, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2010, filed on August 6, 2010, in File No. 1-3480*

+10(s)	Form of Notice of Expiration of Coverage Period - Change of Control Employment Agreement, dated June 15, 2010, sent by MDU Resources Group, Inc. to William E. Schneider, John G. Harp, Steven L. Bietz, David L. Goodin, William R. Connors, Mark A. Del Vecchio, Nicole A. Kivisto, Cynthia J. Norland, Paul K. Sandness, Doran N. Schwartz, and John P. Stumpf, filed as Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2010, filed on August 6, 2010, in File No. 1-3480*
+10(t)	Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, filed as Exhibit 10.1 to Form 8-K dated August 12, 2010, filed on August 17, 2010, in File No. 1-3480*
+10(u)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of December 31, 2011**
+10(v)	Employment Letter for J. Kent Wells, dated March 9, 2011**
+10(w)	MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan 2011 Fidelity President and CEO Award Agreement**
+10(x)	MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as adopted November 17, 2011**
+10(y)	MDU Resources Group, Inc. 401(k) Retirement Plan, as restated March 1, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*
+10(z)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 29, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2011, filed on May 5, 2011, in File No. 1-3480*
+10(aa)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2011, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*
+10(ab)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*
+10(ac)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2011**
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**
21	Subsidiaries of MDU Resources Group, Inc.**
23(a)	Consent of Independent Registered Public Accounting Firm**
23(b)	Consent of Ryder Scott Company, L.P.**
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**
95	Mine Safety Disclosures**

99 Ryder Scott Company, L.P. report dated January 10, 2012**

101 The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011, 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 in summary and detail, (vi) Schedule I - Condensed Financial Information of Registrant, tagged in summary and detail and (vii) Schedule II - Consolidated Valuation and Qualifying Accounts, tagged in summary and detail

* Incorporated herein by reference as indicated.

** Filed herewith.

\+ Management contract, compensatory plan or arrangement.

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

Signatures

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

MDU Resources Group, Inc.

Date: February 24, 2012 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 24, 2012
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 24, 2012
/s/ Nicole A. Kivisto Nicole A. Kivisto (Vice President, Controller and Chief Accounting Officer)	Chief Accounting Officer	February 24, 2012
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 24, 2012
/s/ Thomas Everist Thomas Everist	Director	February 24, 2012
/s/ Karen B. Fagg Karen B. Fagg	Director	February 24, 2012
/s/ A. Bart Holaday A. Bart Holaday	Director	February 24, 2012
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 24, 2012
/s/ Thomas C. Knudson Thomas C. Knudson	Director	February 24, 2012

/s/ Richard H. Lewis Richard H. Lewis	Director	February 24, 2012
/s/ Patricia L. Moss Patricia L. Moss	Director	February 24, 2012
/s/ John K. Wilson John K. Wilson	Director	February 24, 2012

Bylaws of

MDU RESOURCES

GROUP, INC.

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TO BYLAWS

BYLAWS OF
MDU RESOURCES GROUP, INC.

OFFICES

1.01 **Registered Office**. The registered office shall be in the City of Wilmington, County of New Castle, State of Delaware.

1.02 **Other Offices**. The Corporation may also have offices at such other places, both within and without the State of Delaware, as the Board of Directors may from time to time determine or the business of the Corporation may require.

MEETINGS OF STOCKHOLDERS

2.01 **Place of Meetings**. All meetings of the stockholders for the election of Directors shall be held in the City of Bismarck, State of North Dakota, at such place as may be fixed from time to time by the Board of Directors, or at such other place, either within or without the State of Delaware, as shall be designated from time to time by the Board of Directors, or, in the sole discretion of the Board of Directors, by means of remote communication as authorized by the laws of Delaware, as shall be stated in the notice of the meeting. Meetings of stockholders for any other purpose may be held at such time and place, within or without the State of Delaware, or, in the sole discretion of the Board of Directors, by means of remote communication as authorized by the laws of Delaware as shall be stated in the notice of the meeting or in a duly executed waiver of notice thereof.

2.02 **Annual Meetings.** Annual meetings of stockholders shall be held on the fourth Tuesday of April in each year, if not a legal holiday, and if a legal holiday, then on the next secular day following, at 11:00 A.M., or at such other date and time as shall be designated from time to time by the Board of Directors and stated in the notice of the meeting, at which they shall elect a Board of Directors and transact such other business as may properly be brought before the meeting. The election of directors shall be by written ballot including, if authorized by the Board of Directors, by ballot submitted by electronic transmission in compliance with the laws of Delaware.

Except as otherwise provided in the Certificate of Incorporation or these Bylaws, each director shall be elected by the vote of the majority of the votes cast with respect to the director at any meeting for the election of directors at which a quorum is present, provided that if, as of the day next preceding the date the Corporation first gives its notice of meeting for such meeting of stockholders, the number of nominees (including any nominees stockholders have proposed to nominate by giving notice pursuant to Section 2.08 hereof) exceeds the number of directors to be elected, the directors shall be elected by a plurality of the votes of the shares present in person or represented by proxy at any such meeting and entitled to vote on the election of directors. For purposes of this Section, a majority of the votes cast means that the number of votes cast "for" a director's election must exceed the number of votes cast "against" that director's election (with "abstentions" and "broker nonvotes" not counted as a vote cast either "for" or "against" that director's election). If directors are to be elected by a plurality of the votes of the shares present in person or represented by proxy at any such meeting and entitled to vote on the election of directors, stockholders shall not be permitted to vote "against" a nominee.

2.03 **Notice of Annual Meeting**. Notice, in writing or by a form of electronic transmission in compliance with the laws of Delaware, of the annual meeting, stating the place, if any, date and hour of the meeting, and the means of remote communications, if any, by which stockholders and proxy holders may be deemed to be present in person and vote at such meeting, shall be given to each stockholder entitled to vote at such meeting not less than ten nor more than sixty days before the date of the meeting.

2.04 **Stockholders List**. The officer who has charge of the stock ledger of the Corporation shall prepare and make, at least ten days before every meeting of the stockholders, a complete list of the stockholders entitled to vote at the meeting, arranged in alphabetical order, and showing the address of each stockholder and the number of shares registered in the name of each stockholder. Such list shall be open to the examination of any stockholder, for any purpose germane to the meeting, for a period of at least ten days prior to the meeting: (i) on a reasonably accessible electronic network, provided that the information required to gain access to such list is provided with the notice of the meeting or (ii) during ordinary business hours, at the principal place of business of the Corporation. If the meeting is to be held at a place, then the list shall also be produced and kept at the time and place of the meeting during the whole time thereof, and may be inspected by any stockholder who is present. If the meeting is to be held solely by means of remote communication, then the list shall also be open to the examination of any stockholder during the meeting on a reasonably accessible electronic network, and the information required to access the electronic list shall be provided with the notice of the meeting.

2.05 **Notice of Special Meeting.** Notice of a special meeting, in writing or by a form of electronic transmission as determined solely by the Board of Directors in compliance with the laws of Delaware, stating the place, date and hour of the meeting, the means of remote communications, if any, by which the stockholders and proxy holders may be deemed to be present in person and vote at such meeting, and the purpose or purposes for which the meeting is called, shall be given not less than ten (10) nor more than sixty (60) days before the date of the meeting, to each stockholder entitled to vote at such meeting. Business transacted at a special meeting of stockholders shall be confined to the purpose or purposes of the meeting specified in the notice of meeting (or supplement thereto) given by or at the direction of the Board of Directors. Stockholders may not make nominations for directors or bring any business before a special meeting of stockholders.

2.06 **Quorum**. The holders of a majority of the stock issued and outstanding and entitled to vote in person or by proxy, shall constitute a quorum at all meetings of the stockholders for the transaction of business, except as provided herein and except as otherwise provided by statute or by the Certificate of Incorporation. If, however, such quorum shall not be present or represented at any meeting of the stockholders, the stockholders entitled to vote thereat, present in person or represented by proxy, shall have power to adjourn the meeting from time to time, without notice of the adjourned meeting, if the time, place, thereof, and the means of remote communications, if any, by which stockholders and proxy holders

may be deemed to be present in person and vote at such adjourned meeting are announced at the meeting at which the adjournment is taken. At such adjourned meeting at which a quorum shall be present or represented, any business may be transacted which might have been transacted at the meeting as originally notified. If the adjournment is for more than thirty days, or if, after the adjournment, a new record date is fixed for the adjourned meeting, a notice of the adjourned meeting shall be given to each stockholder of record entitled to vote at the meeting.

2.07 **Voting Rights**. When a quorum is present at any meeting, the vote of the holders of a majority of the stock having voting power, present in person or represented by proxy, shall decide any question brought before such meeting, unless the question is one upon which, by express provision of the statutes, the Certificate of Incorporation or these Bylaws, a different vote is required, in which case such express provision shall govern and control the decision of such question. Unless otherwise provided in the Certificate of Incorporation, each stockholder shall, at every meeting of the stockholders, be entitled to one vote in person or by proxy for each share of the capital stock having voting power held by such stockholder, but no proxy shall be voted on after three years from its date, unless the proxy provides for a longer period.

2.08 **Nominations for Director.** Nominations of persons for election to the Board of Directors of the Corporation may be made only (i) by the Board of Directors at any meeting of stockholders and (ii) at an annual meeting of stockholders, by any stockholder of the Corporation who is entitled to vote for the election of directors and who has complied with the procedures established by this Section 2.08. For a nomination to be properly brought before an annual meeting by a stockholder, the stockholder intending to make the nomination (the "Proponent") must have given timely and proper notice thereof in writing to the Secretary of the Corporation, in accordance with, and containing all information and the completed questionnaire provided for in, this Section 2.08.

To be timely, a Proponent's notice must be delivered to or mailed to the Secretary of the Corporation and received at the principal executive offices of the Corporation not later than the close of business 90 days prior to the first anniversary of the preceding year's annual meeting of stockholders; provided, however, in the event the date of the annual meeting is advanced more than 30 days prior to such anniversary date or delayed more than 60 days after such anniversary date then to be timely such notice must be received by the Corporation not later than the close of business on the later of the 90th day prior to the date of the meeting or the 10th day following the date of Public Disclosure (defined below) of the date of the annual meeting. In no event shall any adjournment or postponement of an annual meeting of stockholders or announcement thereof commence a new time period or extend any time period for the giving of a Proponent's notice as required by this Section 2.08.

A Proponent's notice to the Secretary shall set forth: (a) as to each person the Proponent proposes to nominate for election as a director at the annual meeting, (i) the name, age, business address, residence address and telephone number of such nominee and the name, business address and residence address of any Nominee Associated Persons (defined below), (ii) the principal occupation or employment of such nominee, (iii) the class and number of shares of stock of the Corporation that are owned (beneficially and of record) by or on behalf of such nominee and by or on behalf of any Nominee Associated Person, as of

the date of the Proponent's notice, (iv) a description of such nominee's qualifications to be a director and (v) a statement as to whether such nominee would be an independent director, and the basis therefor, under the listing standards of the New York Stock Exchange and the Corporate Governance Guidelines and (b) as to the Proponent and any Stockholder Associated Person (defined below) on whose behalf the nomination is being made, (i) the name and address of the Proponent, and any holder of record of the Proponent's shares of stock, as they appear on the Corporation's books, and of any Stockholder Associated Person, (ii) the class and number of shares of stock of the Corporation that are owned (beneficially and of record) by or on behalf of the Proponent and by or on behalf of any Stockholder Associated Person, as of the date of the Proponent's notice, the date such shares were acquired and the investment intent with respect thereto, (iii) a representation and agreement that the Proponent will notify the Corporation in writing of the class and number of shares of stock of the Corporation that are owned (beneficially and of record) by or on behalf of the Proponent and by or on behalf of any Stockholder Associated Person, as of the record date for the meeting, not later than the close of business on the third business day following the later of the record date or the date of Public Disclosure of the record date, (iv) a description of all purchases and sales of, or other transactions involving in any way, shares of stock of the Corporation by or on behalf of the Proponent and by or on behalf of any Stockholder Associated Person during the twenty-four month period prior to the date of the Proponent's notice, including the date of the transactions, the class and number of shares and the consideration (without regard to whether such shares were or were not owned by the Proponent or any such person), (v) a description of any agreement, arrangement or understanding, including any Derivative Instrument (defined below), that has been entered into or is in effect as of the date of the Proponent's notice, by or on behalf of the Proponent, any Stockholder Associated Person, any nominee or any Nominee Associated Person, the effect or intent of which is to mitigate loss to, manage risk or benefit of stock price changes for, or increase or decrease the voting power of, the Proponent, any Stockholder Associated Person, any nominee or any Nominee Associated Person with respect to the Corporation's securities, (vi) a representation and agreement that the Proponent will notify the Corporation in writing of any such agreement, arrangement or understanding, including any Derivative Instrument, that has been entered into or is in effect as of the record date for the meeting, not later than the close of business on the third business day following the later of the record date or the date of Public Disclosure of the record date, (vii) a description of any other agreement, arrangement or understanding that has been entered into or is in effect as of the date of the Proponent's notice, between or among the Proponent, any Stockholder Associated Person, any nominee, any Nominee Associated Person or any other person, and that relates to such nomination or such nominee's service as a director of the Corporation, (viii) a representation and agreement that the Proponent will notify the Corporation in writing of any such agreement, arrangement or understanding that has been entered into or is in effect as of the record date for the meeting, not later than the close of business on the third business day following the later of the record date or the date of Public Disclosure of the record date, (ix) a representation that the Proponent is the holder of record or beneficial owner of shares of stock of the Corporation entitled to vote for the election of directors at the annual meeting and intends to appear in person or by proxy at the meeting to nominate any such nominee and (x) a representation as to whether the Proponent intends to deliver a proxy statement and/or form of proxy to stockholders and/or otherwise to solicit proxies from stockholders in support of such nomination.

The Proponent's notice shall also include a completed questionnaire (in the form provided by the Secretary of the Corporation upon request by the Proponent) signed by such nominee with respect to information of the type required by the Corporation's Questionnaires for Directors and Officers of the Corporation in connection with the Annual Meeting of Stockholders and Various Reports to the Securities and Exchange Commission. The completed questionnaire shall include a statement that such nominee, if elected, before such nominee is nominated to serve on the Board of Directors at the next meeting of stockholders at which such nominee would face election, will tender to the Board of Directors his or her irrevocable resignation that will be effective in an uncontested election of Directors only, upon (i) such nominee's receipt of a greater number of votes "against" election than votes "for" election at the Corporation's meeting of stockholders and (ii) acceptance of such resignation by the Board of Directors, in accordance with the Corporation's Corporate Governance Guidelines. The questionnaire shall also include a representation and agreement that such nominee (i) is not and will not become a party to (A) any agreement, arrangement or understanding with, and has not given any commitment or assurance to, any person or entity as to how such nominee, if elected as a director of the Corporation, will act or vote on any issue or question (a "Voting Commitment") that has not been, or will not be within three business days thereafter, disclosed to the Corporation or (B) any Voting Commitment that could limit or interfere with the nominee's ability to comply, if elected as a director of the Corporation, with such nominee's fiduciary duties under applicable law, (ii) is not and will not become a party to any agreement, arrangement or understanding with any person or entity other than the Corporation with respect to any direct or indirect compensation, reimbursement or indemnification in connection with service or action as a director of the Corporation that has not been, or will not be within three business days thereafter, disclosed to the Corporation and (iii) in such nominee's individual capacity and on behalf of any person or entity on whose behalf the nomination is being made, would be in compliance, if elected as a director of the Corporation, and will comply, with applicable law and all applicable corporate governance, code of conduct and ethics, conflict of interest, corporate opportunities, confidentiality and stock ownership and trading policies and guidelines of the Corporation.

No person proposed to be nominated by a stockholder shall be eligible for election as a director of the Corporation unless such person is nominated in accordance with the procedures set forth in this Section 2.08. If the Proponent intending to nominate a person for election as a director of the Corporation at an annual meeting pursuant to this Section 2.08 does not give timely and proper notice thereof in writing to the Secretary of the Corporation, in accordance with, and containing all information and the completed questionnaire provided for in, this Section 2.08, or if the Proponent (or a qualified representative of the Proponent) does not appear at the meeting to nominate such person for election as a director of the Corporation, then, in any such case, such proposed nomination shall not be made, notwithstanding the fact that proxies in respect of such nomination may have been solicited or obtained. The chairman of the meeting shall, if the facts warrant, determine that the nomination was not properly made in accordance with the provisions of this Section 2.08, and, if the chairman should so determine, he or she shall declare to the meeting that such nomination was not properly made and shall be disregarded.

The requirements of this Section 2.08 shall apply to the nomination by a stockholder of a person for election as a director without regard to whether such nomination also is intended to be included in the

Corporation's proxy statement pursuant to Rule 14a-8 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or whether such nomination is presented to stockholders by means of a proxy solicitation by any person other than by or on behalf of the Board of Directors.

For purposes of the Bylaws:

"Derivative Instrument" means any option, warrant, convertible security, stock appreciation right, swap or similar right with an exercise or conversion privilege or a settlement payment or mechanism at a price related to any class or series of shares of stock of the Corporation or with a value derived in whole or in part from the value of any class or series of shares of stock of the Corporation, whether or not such instrument or right shall be subject to settlement in the underlying class or series of shares of stock of the Corporation or otherwise directly or indirectly owned and any other direct or indirect opportunity to profit or share in any profit derived from any increase or decrease in the value of shares of stock of the Corporation.

"Nominee Associated Person" of any nominee for election as a director means (i) any affiliate or associate (as such terms are defined for purposes of the Exchange Act) of the nominee and any other person acting in concert with any of the foregoing, (ii) any beneficial owner of shares of stock of the Corporation owned of record or beneficially by such nominee and (iii) any person controlling, controlled by or under common control with such Nominee Associated Person.

"Public Disclosure" means disclosure made in a press release reported by Dow Jones News Service, Associated Press or a comparable national news service or in a document filed by the Corporation pursuant to Section 13, 14 or 15(d) of the Exchange Act.

"Stockholder Associated Person" of any stockholder means (i) any affiliate or associate (as such terms are defined for purposes of the Exchange Act) of the stockholder and any other person acting in concert with any of the foregoing, (ii) any beneficial owner of shares of stock of the Corporation owned of record or beneficially by such stockholder and (iii) any person controlling, controlled by or under common control with such Stockholder Associated Person.

2.09 **Business at Meetings of Stockholders.** At any meeting of stockholders, only such business shall be transacted as shall have been properly brought before the meeting. To be properly brought before a meeting of stockholders, business must be (a) specified in the notice of meeting (or any supplement thereto) given by or at the direction of the Board of Directors, (b) otherwise properly brought before the meeting by or at the direction of the Board of Directors or (c) in the case of an annual meeting of stockholders, properly brought before the meeting by a stockholder who is entitled to vote and who has complied with the procedures established by this Section 2.09. For business to be properly brought before an annual meeting by a stockholder (other than the nomination of a person for election as a director, which is governed by Section 2.08 of these Bylaws), the Proponent (defined in Section 2.08) must have given timely and proper notice thereof in writing to the Secretary of the Corporation, in accordance with, and containing all information provided for, in this Section 2.09, and such business must be a proper matter for stockholder action under the General Corporation Law of Delaware.

To be timely, a Proponent's notice must be delivered to or mailed to the Secretary of the Corporation and received at the principal executive offices of the Corporation not later than the close of business 90 days prior to the first anniversary of the preceding year's annual meeting of stockholders; provided, however, in the event the date of the annual meeting is advanced more than 30 days prior to such anniversary date or delayed more than 60 days after such anniversary date, then to be timely such notice must be received by the Corporation not later than the close of business on the later of the 90th day prior to the date of the meeting or the 10th day following the date of Public Disclosure (defined in Section 2.08) of the date of the annual meeting. In no event shall any adjournment or postponement of an annual meeting of stockholders or announcement thereof commence a new time period or extend any time period for the giving of a Proponent's notice as required by this Section 2.09.

A Proponent's notice to the Secretary shall set forth: (a) as to each matter the Proponent proposes to bring before the annual meeting, a description of the business desired to be brought before the annual meeting, the reasons for transacting such business at the meeting and the text of any resolutions to be proposed, and whether the Proponent has communicated with any other stockholder or beneficial owner of shares of stock of the Corporation regarding such business and (b) as to the Proponent and any Stockholder Associated Person (defined in Section 2.08) on whose behalf the proposal is being made, (i) the name and address of the Proponent, and any holder of record of the Proponent's shares of stock, as they appear on the Corporation's books, and of any Stockholder Associated Person, (ii) the class and number of shares of stock of the Corporation that are owned (beneficially and of record) by or on behalf of the Proponent and by or on behalf of any Stockholder Associated Person, as of the date of the Proponent's notice, the date such shares were acquired and the investment intent with respect thereto, (iii) a representation and agreement that the Proponent will notify the Corporation in writing of the class and number of shares of stock of the Corporation that are owned (beneficially and of record) by or on behalf of the Proponent and by or on behalf of any Stockholder Associated Person, as of the record date for the meeting, not later than the close of business on the third business day following the later of the record date or the date of Public Disclosure of the record date, (iv) a description of all purchases and sales of, or other transactions involving in any way, shares of stock of the Corporation by or on behalf of the Proponent and by or on behalf of any Stockholder Associated Person during the twenty-four month period prior to the date of the Proponent's notice, including the date of the transactions, the class and number of shares and the consideration (without regard to whether such shares involved were or were not owned by the Proponent or any such person), (v) a description of any agreement, arrangement or understanding, including any Derivative Instrument (defined in Section 2.08), that has been entered into or is in effect as of the date of the Proponent's notice, by or on behalf of the Proponent or any Stockholder Associated Person, the effect or intent of which is to mitigate loss to, manage risk or benefit of stock price changes for, or increase or decrease the voting power of, the Proponent or any Stockholder Associated Person with respect to the Corporation's securities, (vi) a representation and agreement that the Proponent will notify the Corporation in writing of any such agreement, arrangement or understanding, including any Derivative Instrument, that has been entered into or is in effect as of the record date for the meeting, not later than the close of business on the third business day following the later of the record date or the date of Public Disclosure of the record date, (vii) any material interest of the Proponent or any Stockholder Associated Person in such business, (viii) a description of any other agreement, arrangement or understanding that has been entered into or is in effect as of the date of the Proponent's notice, between or among the Proponent, any Stockholder Associated Person or any other person, and that relates to such business, (ix) a representation and agreement that the Proponent will notify the Corporation in writing of any such agreement, arrangement or understanding that has been entered into or is in effect as of the record date for the meeting, not later than the close of business on the third business day following the later of the record date or the date of Public Disclosure of the record date, (x) a representation that the Proponent is the holder of record or beneficial owner of shares of stock of the Corporation entitled to vote for the election of directors at the annual meeting and intends to appear in person or by proxy at the meeting to propose such business and (xi) a representation as to whether the Proponent intends to deliver a proxy statement and/or form of proxy to stockholders and/or otherwise to solicit proxies from stockholders in support of such proposal.

No business proposed by a stockholder shall be transacted at an annual meeting of stockholders except in accordance with the procedures set forth in this Section 2.09. If the Proponent intending to propose business at an annual meeting pursuant to this Section 2.09 does not give timely and proper notice thereof in writing to the Secretary of the Corporation, in accordance with, and containing all information provided for in, this Section 2.09, or if the Proponent (or a qualified representative of the Proponent) does not appear at the meeting to present the proposed business, then, in any such case, such business shall not be transacted, notwithstanding the fact that proxies in respect of such business may have been solicited or obtained. The chairman of the meeting shall, if the facts warrant, determine that the business was not properly brought before the meeting in accordance with the provisions of this Section 2.09, and, if the chairman should so determine, he or she shall declare to the meeting that such business was not properly brought before the meeting and shall not be transacted.

The requirements of this Section 2.09 shall apply to any business to be brought before an annual meeting of stockholders by a stockholder (other than the nomination by a stockholder of a person for election as a director, which is governed by Section 2.08 of these Bylaws) without regard to whether such business also is intended to be included in the Corporation's proxy statement pursuant to Rule 14a-8 of the Exchange Act or whether such business is presented to stockholders by means of a proxy solicitation by any person other than by or on behalf of the Board of Directors.

DIRECTORS

3.01 **Authority of Directors**. The business of the Corporation shall be managed by its Board of Directors which may exercise all such powers of the Corporation and do all such lawful acts and things as are not by statute or by the Certificate of Incorporation or by these Bylaws directed or required to be exercised or done by the stockholders.

3.02 **Qualifications.** A person who is not an officer of the Corporation shall be ineligible to serve as a Director beyond the first regular meeting of the Board of Directors after the date he shall have attained the age of seventy-four (74). A person who is a "high ranking executive" (as defined in Section 5.01) of the Corporation shall be ineligible to serve as a Director beyond the first regular meeting of the Board of Directors after the date he shall have attained the age of sixty-five (65). A person shall be ineligible as a

Director if, at the time he would otherwise be eligible for election, he is a former officer of the Corporation. Other restrictions and qualifications for Directors may be fixed from time to time by resolution passed by a majority of the whole Board of Directors.

3.03 **Place of Meetings**. The Board of Directors of the Corporation may hold meetings, both regular and special, either within or without the State of Delaware.

3.04 **Annual Meetings**. The first meeting of each newly elected Board of Directors shall be held at such time and place as shall be specified in a notice given as herein provided for regular meetings of the Board of Directors, or as shall be specified in a duly executed waiver of notice thereof.

3.05 **Regular Meetings.** Regular meetings of the Board of Directors may be held at the office of the Corporation in Bismarck, North Dakota, on the second Thursday following the first Monday of February, May, August and November of each year; provided, however, that if a legal holiday, then on the next preceding day that is not a legal holiday. Regular meetings of the Board of Directors may be held at other times and other places within or without the State of North Dakota on at least five days' notice to each Director, either personally or by mail, telephone or another form of electronic transmission in compliance with the laws of Delaware.

3.06 **Special Meetings.** Special meetings of the Board may be called by the Chairman of the Board, Chief Executive Officer or President on three days' notice to each Director, either personally or by mail, telephone or another form of electronic transmission in compliance with the laws of Delaware; special meetings shall be called by the Chairman, Chief Executive Officer, President or Secretary in like manner and on like notice on the written request of a majority of the Board of Directors.

3.07 **Quorum**. At all meetings of the Board, a majority of the Directors shall constitute a quorum for the transaction of business and the act of a majority of the Directors present at any such meeting at which there is a quorum shall be the act of the Board of Directors, except as may be otherwise specifically provided by statute, the Certificate of Incorporation or by these Bylaws. If a quorum shall not be present at any meeting of the Board of Directors, the Directors present may adjourn the meeting from time to time, without notice other than announcement at the meeting, until a quorum shall be present.

3.08 **Participation of Directors by Conference Telephone**. Unless otherwise restricted by the Certificate of Incorporation or these Bylaws, any member of the Board, or of any committee designated by the Board, may participate in any meeting of such Board or committee by means of conference telephone or other communications equipment by means of which all persons participating in the meeting can hear each other. Participation in any meeting by means of conference telephone or other communications equipment shall constitute presence in person at such meeting.

3.09 **Written Action of Directors**. Unless otherwise restricted by the Certificate of Incorporation or these Bylaws, any action required or permitted to be taken at any meeting of the Board of Directors or of any committee thereof may be taken without a meeting, if all members of the Board or committee, as the case may be, consent thereto in writing or by electronic transmission, and the writing or writings or

electronic transmission or transmissions are filed with the minutes of proceedings of the Board or committee.

3.10 **Committees.** The Board of Directors may by resolution passed by a majority of the whole Board designate one or more committees, each committee to consist of two or more Directors of the Corporation. The Board may designate one or more Directors as alternate members of any committee who may replace any absent or disqualified member at any meeting of the committee. In the absence or disqualification of a member of a committee, the member or members thereof present at any meeting and not disqualified from voting, whether or not he or they constitute a quorum, may unanimously appoint another member of the Board of Directors to act at the meeting in the place of any such absent or disqualified member. The Chairman of the Board shall appoint another member of the Board of Directors to fill any committee vacancy which may occur. At all meetings of any such committee, fifty percent of the total number of committee members shall constitute a quorum for the transaction of business and the act of a majority of the committee members present at any such meeting at which there is a quorum shall be the act of any such committee, except as may be otherwise specifically provided by statute, the Certificate of Incorporation or by these Bylaws. Any such committee shall have, and may exercise, the power and authority specifically granted by the Board to the committee, but no such committee shall have the power or authority to amend the Certificate of Incorporation, adopt an agreement of merger or consolidation, recommend to the stockholders the sale, lease or exchange of the Corporation's property and assets, recommend to the stockholders a dissolution of the Corporation or a revocation of a dissolution, or amend the Bylaws of the Corporation. Such committee or committees shall have such name or names as may be determined from time to time by resolution adopted by the Board of Directors.

3.11 **Reports of Committees**. Each committee shall keep regular minutes of its meetings and report the same to the Board of Directors when required.

3.12 **Compensation of Directors**. Unless otherwise restricted by the Certificate of Incorporation, the Board of Directors shall have the authority to fix the compensation of Directors. The Directors may be paid their expenses, if any, of attendance at each meeting of the Board of Directors and may be paid a fixed sum for attendance at each meeting of the Board of Directors or a stated salary as Director. No such payment shall preclude any Director from serving the Corporation in any other capacity and receiving compensation therefor. Members of special or standing committees may be allowed compensation for attending committee meetings.

3.13 **Chairman of the Board**. The Chairman of the Board of Directors shall be chosen by the Board of Directors at its first meeting after the annual meeting of the stockholders of the Corporation. The Chairman shall preside at all meetings of the Board of Directors and stockholders of the Corporation, and shall, subject to the direction and control of the Board, be its representative and medium of communication, and shall perform such duties as may from time to time be assigned to the Chairman of the Board.

3.14 **Lead Director.** At the first meeting of the Board of Directors after the annual meeting of the stockholders, those Directors who are not employees of the Corporation ("Non-employee Directors") shall, by a resolution adopted by a majority of the Non-employee Directors present at the meeting, choose a Lead Director whenever an employee Director is serving as Chairman of the Board of Directors. During the period of time a Non-employee Director serves as Chairman of the Board, no Lead Director will be chosen. The Lead Director shall have such duties and responsibilities as shall be fixed from time to time by resolution adopted by a majority of the whole Board of Directors.

NOTICES

4.01 **Notices.** Whenever, under the provisions of the statutes or of the Certificate of Incorporation or of these Bylaws, notice is required to be given to any Director or stockholder, it shall not be construed to mean personal notice, but such notice may be given in writing, by mail, addressed to such Director or stockholder, at his address as it appears on the records of the Corporation, with postage thereon prepaid, and such notice shall be deemed to be given at the time when the same shall be deposited in the United States mail. Notice to Directors may also be given by telephone or another form of electronic transmission in compliance with the laws of Delaware. Notice to the stockholders may also be given by a form of electronic transmission consented to by the stockholder to whom the notice is given, as provided by the laws of Delaware.

4.02 **Waiver**. Whenever notice is required to be given under any provision of the statutes or the Certificate of Incorporation or these Bylaws, a written waiver, signed by the person entitled to notice, or a waiver by electronic transmission by the person entitled to notice, whether before or after the time stated therein, shall be deemed equivalent to notice.

OFFICERS

5.01 **Election, Qualifications.** The officers of the Corporation shall be chosen by the Board of Directors at its first meeting after each annual meeting of the stockholders and shall include a President, a Chief Executive Officer, a Vice President, a Secretary, a Treasurer and a General Counsel. The Board of Directors may also choose additional Vice Presidents, and one or more Assistant Vice Presidents, Assistant Secretaries and Assistant Treasurers. Any number of offices may be held by the same person, unless the Certificate of Incorporation or these Bylaws otherwise provide. Except for an officer serving as a Director who may serve through the first regular meeting of the Board of Directors after he has attained the age of sixty-five (65), no "high ranking executive" of the Corporation may serve in that capacity beyond the date he shall have attained the age of sixty-five (65); "high ranking executive" shall mean the President, the Chief Executive Officer, any Vice President, the Secretary, the Treasurer, the General Counsel, the chief executive officers of the Corporation's public utility divisions, and any other officer of the Corporation so designated by the Board of Directors.

5.02 **Additional Officers**. The Board of Directors may appoint such other officers and agents as it shall deem necessary, who shall hold their offices for such terms and shall exercise such powers and perform such duties as shall be determined from time to time by the Board.

5.03 **Salaries**. The salaries of all principal officers of the Corporation shall be fixed by the Board of Directors.

5.04 **Term**. The officers of the Corporation shall hold office until their successors are chosen and qualify. Any officer elected or appointed by the Board of Directors may be removed at any time by the affirmative vote of a majority of the Board of Directors. Any vacancy occurring in any office of the Corporation shall be filled by the Board of Directors.

5.05 **Chief Executive Officer**. The Chief Executive Officer shall, subject to the authority of the Board of Directors, determine the general policies of the Corporation. The Chief Executive Officer shall submit a report of the operations of the Company for the fiscal year to the stockholders at their annual meeting and from time to time shall report to the Board of Directors all matters within his knowledge which the interests of the Corporation may require be brought to the Board's notice.

5.06 **The President**. The President shall have general and active management of the business of the Corporation and shall see that all orders and resolutions of the Board of Directors are carried into effect.

5.07 **The Vice Presidents**. In the absence of the President or in the event of his inability or refusal to act, the Vice President (or in the event there be more than one Vice President, the Vice Presidents in the order designated, or in the absence of any designation, then in the order of their election) shall perform the duties of the President, and when so acting, shall have all the powers of and be subject to all the restrictions upon the President. The Vice Presidents shall perform such other duties and have such other powers as the Board of Directors may from time to time prescribe.

5.08 **The Secretary and Assistant Secretaries**. The Secretary shall record all the proceedings of the meetings of the stockholders and Directors in a book to be kept for that purpose. He shall give, or cause to be given, notice of all meetings of the stockholders and special meetings of the Board of Directors, and shall perform such other duties as may be prescribed by the Board of Directors or Chief Executive Officer, under whose supervision he shall be. He shall have custody of the corporate seal of the Corporation and he, or an assistant secretary, shall have authority to affix the same to any instrument requiring it. The Board of Directors may give general authority to any other officer to affix the seal of the Corporation.

The Assistant Secretary, or if there be more than one, the Assistant Secretaries in the order determined by the Board of Directors (or if there be no such determination, then in the order of their election) shall, in the absence of the Secretary or in the event of his inability or refusal to act, perform the duties and exercise the powers of the Secretary and shall perform such other duties and have such other powers as the Board of Directors may from time to time prescribe.

5.09 **Treasurer and Assistant Treasurers**. The Treasurer shall have the custody of the corporate funds and securities and shall keep full and accurate accounts of receipts and disbursements in books belonging to the Corporation and shall deposit all moneys and other valuable effects in the name and to the credit of the Corporation in such depositories as may be designated by the Board of Directors.

He shall disburse the funds of the Corporation as may be ordered by the Board of Directors, taking proper vouchers for such disbursements, and shall render to the President and the Board of Directors, at its regular meetings, or when the Board of Directors so requires, an account of all his transactions as Treasurer and of the financial condition of the Corporation.

If required by the Board of Directors, he shall give the Corporation a bond (which shall be renewed every six years) in such sum and with such surety or sureties as shall be satisfactory to the Board of Directors for the faithful performance of the duties of his office and for the restoration to the Corporation, in case of his death, resignation, retirement or removal from office, of all books, papers, vouchers, money and other property of whatever kind in his possession or under his control belonging to the Corporation.

The Assistant Treasurer, or if there shall be more than one, the Assistant Treasurers in the order determined by the Board of Directors (or if there be no such determination, then in the order of their election), shall, in the absence of the Treasurer or in the event of his inability or refusal to act, perform the duties and exercise the powers of the Treasurer and shall perform such other duties and have such other powers as the Board of Directors may from time to time prescribe.

5.10 **General Counsel.** The General Counsel shall be the legal advisor to the Corporation, the Chairman of the Board, the Chief Executive Officer, the Board of Directors and committees of the Board of Directors and provide legal counsel to all business segments of the Corporation. The General Counsel shall be responsible for the management of all legal matters involving the Corporation.

The General Counsel shall be responsible for the review of the adequacy of the Corporation's corporate governance procedures and for reporting to senior management, the Board of Directors and committees of the Board of Directors on recommended changes, except in those instances in which such duties have been delegated by the Board of Directors to another officer or agent of the Corporation. The General Counsel shall have responsibility for monitoring and assessing developments in corporate governance including, but not limited to, stock exchange listing standards, legislative enactments, administrative agency regulations and judicial decisions. The General Counsel shall report to senior management, the Board of Directors and committees of the Board of Directors regarding matters of significant importance and make recommendations regarding corporate governance guidelines, policies and procedures.

5.11 **Authority and Duties**. In addition to the foregoing authority and duties, all officers of the Corporation shall respectively have such authority and perform such duties in the management of the business of the Corporation as may be designated from time to time by the Board of Directors.

5.12 **Execution of Instruments.** All deeds, bonds, mortgages, notes, contracts and other instruments shall be executed on behalf of the Corporation by the Chief Executive Officer, the President, any Vice President or Assistant Vice President, the General Counsel or such other officer or agent of the Corporation as shall be duly authorized by the Board of Directors. Any officer or agent executing any such documents on behalf of the Corporation may do so (except as otherwise required by applicable law) either under or without the seal of the Corporation and either individually or with an attestation, according to the requirements of the form of the instrument. If an attestation is required, the document shall be

attested by the Secretary or an Assistant Secretary or by the Treasurer or an Assistant Treasurer or any other officer or agent authorized by the Board of Directors. When authorized by the Board of Directors, the signature of any officer or agent of the Corporation may be a facsimile.

5.13 **Execution of Proxies**. All capital stocks in other corporations owned by the Corporation shall be voted at the meetings, regular and/or special, of stockholders of said other corporations by the Chief Executive Officer or President of the Corporation, or, in the absence of any of them, by a Vice President, and in the event of the presence of more than one Vice President of the Corporation, then by a majority of said Vice Presidents present at such stockholder meetings, and the Chief Executive Officer or President and Secretary of the Corporation are hereby authorized to execute in the name and under the seal of the Corporation proxies in such form as may be required by the corporations whose stock may be owned by the Corporation, naming as the attorney authorized to act in said proxy such individual or individuals as said Chief Executive Officer or President and Secretary shall deem advisable, and the attorney or attorneys so named in said proxy shall, until the revocation or expiration thereof, vote said stock at such stockholder meetings only in the event that none of the officers of the Corporation authorized to execute said proxy shall be present thereat.

CERTIFICATES OF STOCK

6.01 **Certificates**. Shares of the Corporation's stock may be certificated or uncertificated, as provided under Delaware law. All certificates of stock of the Corporation shall be numbered and shall be entered in the books of the Corporation as they are issued. They shall exhibit the holder's name and number of shares and shall be signed by the Chairman of the Board of Directors, or the Chief Executive Officer, the President or a Vice President and by the Treasurer or an Assistant Treasurer or the Secretary or an Assistant Secretary.

6.02 **Signatures**. Any of or all the signatures on the certificates may be facsimile. In case any officer, transfer agent or registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, transfer agent or registrar before such certificate is issued, it may be issued by the Corporation with the same effect as if he were such officer, transfer agent or registrar at the date of issue.

6.03 **Special Designation on Certificates**. If the Corporation shall be authorized to issue more than one class of stock or more than one series of any class, the powers, designations, preferences and relative, participating, optional or other special rights of each class of stock or series thereof and the qualifications, limitations, or restrictions of such preferences and/or rights shall be set forth in full or summarized on the face or back of the certificate which the Corporation shall issue to represent such class or series of stock, provided, that, except as otherwise provided in Section 202 of the General Corporation Law of Delaware in lieu of the foregoing requirements, there may be set forth on the face or back of the certificate which the Corporation shall issue to represent such class or series of stock, a statement that the Corporation will furnish, without charge to each stockholder who so requests, the powers, designations, preferences and relative, participating, optional or other special rights of each class of stock or series thereof and the qualifications, limitations or restrictions of such preferences and/or rights.

6.04 **Lost Certificates**. The Board of Directors may direct a new certificate or certificates to be issued in place of any certificate or certificates theretofore issued by the Corporation alleged to have been lost, stolen or destroyed, upon the making of an affidavit of that fact by the person claiming the certificate of stock to be lost, stolen or destroyed. When authorizing such issue of a new certificate or certificates, the Board of Directors may, in its discretion and as a condition precedent to the issuance thereof, require the owner of such lost, stolen or destroyed certificate or certificates, or his legal representative, to advertise the same in such manner as it shall require and/or to give the Corporation a bond in such sum as it may direct as indemnity against any claim that may be made against the Corporation with respect to the certificate alleged to have been lost, stolen or destroyed.

6.05 **Transfers of Stock**. Transfers of stock shall be made on the books of the Corporation only by the record holder of such stock, or by attorney lawfully constituted in writing, and, in the case of stock represented by a certificate, upon surrender of the certificate.

6.06 **Record Date**. In order that the Corporation may determine the stockholders entitled to notice of or to vote at any meeting of stockholders or any adjournment thereof, or entitled to receive payment of any dividend or other distribution or allotment of any rights, or entitled to exercise any rights in respect of any change, conversion or exchange of stock or for the purpose of any other lawful action, the Board of Directors may fix, in advance, a record date, which shall not be more than sixty days nor less than ten days before the date of such meeting, nor more than sixty days prior to any other action. A determination of stockholders of record entitled to notice of or to vote at a meeting of stockholders shall apply to any adjournment of the meeting; provided, however, that the Board of Directors may fix a new record date for the adjourned meeting.

6.07 **Registered Stockholders.** The Corporation shall be entitled to recognize the exclusive right of a person registered on its books as the owner of shares to receive dividends, and to vote as such owner, and to hold liable for calls and assessments a person registered on its books as the owner of shares, and shall not be bound to recognize any equitable or other claim to or interest in such share or shares on the part of any other person, whether or not it shall have express or other notice thereof, except as otherwise provided by the laws of Delaware.

GENERAL PROVISIONS

7.01 **Dividends**. Dividends upon the capital stock of the Corporation, subject to the provisions of the Certificate of Incorporation, if any, may be declared by the Board of Directors at any regular or special meeting, pursuant to law. Dividends may be paid in cash, in property, or in shares of the capital stock, subject to the provisions of the Certificate of Incorporation.

Before payment of any dividend, there may be set aside out of the funds of the Corporation available for dividends such sum or sums as the Directors from time to time, in their absolute discretion, think proper as a reserve or reserves for meeting contingencies, or for equalizing dividends, or for repairing or maintaining any property of the Corporation, or for such other purpose as the Directors shall think conducive to the interest of the Corporation, and the Directors may modify or abolish any such reserve in the manner in which it was created.

7.02 **Checks**. All checks or demands for money and notes of the Corporation shall be signed by such officer or officers or such other person or persons as the Board of Directors may from time to time designate or as designated by an officer of the company if so authorized by the Board of Directors.

7.03 **Fiscal Year**. The fiscal year of the Corporation shall be the calendar year.

7.04 **Seal**. The corporate seal shall have inscribed thereon the name of the Corporation, the year of its organization and the words "Corporate Seal, Delaware." The seal may be used by causing it or a facsimile thereof to be impressed or affixed or imprinted, or otherwise.

7.05 **Inspection of Books and Records**. Any stockholder of record, in person or by attorney or other agent, shall, upon written demand under oath stating the purpose thereof, have the right, during the usual hours of business, to inspect for any proper purpose the Corporation's stock ledger, a list of its stockholders, and its other books and records, and to make copies or extracts therefrom. A proper purpose shall mean a purpose reasonably related to such person's interest as a stockholder. In every instance where an attorney or other agent shall be the person who seeks the right to inspection, the demand under oath shall be accompanied by a power of attorney or such other writing which authorizes the attorney or other agent to so act on behalf of the stockholder. The demand under oath shall be directed to the Corporation at its registered office in the State of Delaware or at its principal place of business in Bismarck, North Dakota.

7.06 **Amendments**. These Bylaws may be altered, amended or repealed or new Bylaws may be adopted by the stockholders or by the Board of Directors, when such power is conferred upon the

Board of Directors by the Certificate of Incorporation, at any regular meeting of the stockholders

or of the Board of Directors or at any special meeting of the stockholders or of the Board of Directors if notice of such alteration, amendment, repeal or adoption of new Bylaws be contained in the notice of such special meeting.

7.07 **Indemnification of Officers, Directors, Employees and Agents.**

(a) **Indemnification Granted.** The Corporation shall indemnify and hold harmless, to the fullest extent permitted by applicable law as it presently exists or may hereafter be amended, any director or former director or officer or former officer of the Corporation (a "Director or Officer") who was or is made or is threatened to be made a party or is otherwise involved in any action, suit or proceeding, whether civil, criminal, administrative or investigative (a "Proceeding") by reason of the fact that he or she is or was a director or officer of the Corporation or is or was serving at the request of the Corporation as a director, officer, employee or agent of another corporation or of a partnership, limited liability company, joint venture, trust, non-profit entity or other enterprise, including service with respect to employee benefit plans, against expenses (including attorneys' fees), judgments, fines, penalties, excise taxes and penalties assessed with respect to employee benefit plans, and amounts paid in settlement actually and reasonably incurred by such Director or Officer. The Corporation shall be required to indemnify a Director or Officer

in connection with a Proceeding (or part thereof) initiated by such Director or Officer only if the Proceeding (or part thereof) was authorized by the Board of Directors.

(b) **Consent to Settlement or Nonadjudicated Disposition.** No indemnification pursuant to this Section 7.07 shall be required with respect to any settlement or other nonadjudicated disposition of any threatened or pending Proceeding unless the Corporation has given its prior consent to such settlement or disposition.

(c) **Advancement of Expenses.** The Corporation shall pay the expenses incurred by a Director or Officer in defending any Proceeding in advance of its final disposition, provided, however, that the payment of such expenses shall be made only upon receipt of an undertaking by the Director or Officer to repay all amounts advanced if it shall ultimately be determined that the Director or Officer is not entitled to be indemnified.

(d) **Claims.** If a claim for indemnification (following a final full or partial disposition of a Proceeding with respect to which indemnification is sought) or advancement of expenses (including attorneys' fees) under this Section 7.07 is not paid in full within sixty (60) days after a written claim therefor has been received by the Corporation, the Director or Officer may file suit to recover the unpaid amount of such claim and, if successful in whole or in part, shall be entitled to be paid the expense of prosecuting such claim, to the fullest extent permitted by applicable law. In any such action, the Corporation shall have the burden of proving that the Director or Officer was not entitled to the requested indemnification or advancement of expenses under this Section 7.07 or applicable law.

(e) **Other Indemnification and Advancement of Expenses.** The Corporation may provide indemnification and advancement of expenses (including attorneys' fees) to employees and agents to the extent permitted by applicable law.

(f) **Non-exclusivity of Rights.** The rights conferred on any Director or Officer by this Section 7.07 shall not be exclusive of other rights to which such Director or Officer may have or hereafter acquire under any statute, provision of the Certificate of Incorporation, these Bylaws, agreement, vote of stockholders or disinterested directors or otherwise. Nothing in this Section 7.07 shall limit the power of the Corporation or the Board of Directors to grant indemnification and advancement of expenses, including attorneys' fees, to directors, officers, employees and agents otherwise than pursuant to this Section 7.07.

(g) **Other Source Indemnification.** The Corporation's obligation to indemnify any Director or Officer who was or is serving at its request as a director, officer, employee or agent of another corporation or of a partnership, limited liability company, joint venture, trust, non-profit entity or other enterprise shall be reduced by any amount such Director or Officer may collect as indemnification from such other corporation, partnership, limited liability company, joint venture, trust, non-profit entity or other enterprise.

(h) **Repeal or Modification; Legal Representatives.** Any repeal or modification of the foregoing provisions of this Section 7.07 shall not adversely affect any right or protection hereunder of any Director or Officer in respect of any act or omission occurring prior to the time of such repeal or modification. The rights provided to any Director or Officer by this Section 7.07 shall inure to the benefit of such Director's or Officer's legal representative.

7.08 **Severability.** If any provision of these Bylaws (or any portion, including words or phrases, thereof) or the application of any provision (or any portion, including words or phrases, thereof) to any person or circumstance shall be held invalid, illegal or unenforceable in any respect under applicable law by a court of competent jurisdiction, such invalidity, illegality or unenforceability shall not affect any other provisions hereof (or the remaining portion thereof) or the application of such provision to any other persons or circumstances, which unaffected provisions (or portions thereof) shall remain valid, legal and enforceable to the fullest extent permitted by law.

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CREDIT AGREEMENT

among

MDU RESOURCES GROUP, INC.
as Borrower;

VARIOUS LENDERS;

and

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Administrative Agent

WELLS FARGO SECURITIES, LLC
AND
UNION BANK, N.A.,
as Joint Lead Arrangers and Joint Lead Bookrunners

UNION BANK, N.A.,
as Syndication Agent

Closing Date: May 26, 2011

$100,000,000 Revolving Credit Facility

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CREDIT AGREEMENT

This Agreement is entered into as of May 26, 2011, by and among MDU Resources Group, Inc., a Delaware corporation (the **"Borrower"**), the several banks and other financial institutions from time to time party hereto as lenders (the **"Lenders"**), and Wells Fargo Bank, National Association, a national banking association (**"Wells Fargo"**), in its capacity as administrative agent for the Lender Parties, as defined below (in such capacity, together with any successor thereto in such capacity, the **"Administrative Agent"**).

The parties hereto agree as follows:

ARTICLE I
Definitions

Section 1.1 Definitions.

As used in this Agreement:

"ABR Borrowing" means a Borrowing consisting of ABR Loans.

"ABR Loan" means any Loan that bears interest at a rate determined by reference to the Adjusted Base Rate.

"Adjusted Base Rate" means, for any day, an annual rate equal to the highest of (a) the Base Rate, (b) the Federal Funds Rate plus 50 basis points, and (c) the Floating LIBO Rate plus 100 basis points.

"Adjusted LIBO Rate" means, with respect to an Interest Period, the rate (rounded upwards, if necessary, to the nearest 1/16 of 1%) obtained by dividing (a) the applicable LIBO Rate by (b) a percentage equal to 1.00 minus the applicable percentage (expressed as a decimal) prescribed by the Board of Governors of the Federal Reserve System (or any successor thereto) for determining the maximum reserve requirements applicable to eurodollar fundings (currently referred to as "Eurocurrency Liabilities" in Regulation D) or any other maximum reserve requirements applicable to a member bank of the Federal Reserve System with respect to such eurodollar fundings.

"Administrative Agent" means Wells Fargo acting in its capacity as administrative agent for itself and the other Lenders hereunder.

"Administrative Questionnaire" means an Administrative Questionnaire in a form supplied by the Administrative Agent.

"Advance" means an advance by a Lender to the Borrower pursuant to Article II.

"Affiliate" of any Person means any other Person directly or indirectly controlling, controlled by or under the common control with such Person. A Person shall be deemed to control another Person if the controlling Person owns 10% or more of any class of voting securities (or other ownership interests) of the controlled Person or possesses, directly or indirectly, the power to direct or cause the direction of the management or policies of the controlled Person, whether through ownership of stock or other equity interests, by contract or otherwise.

"Aggregate Revolving Commitment Amount" means $100,000,000, as such amount may be reduced pursuant to Section 2.13 or increased pursuant to Section 2.14.

"Aggregate Revolving Facility Outstanding Amount" means the sum of the Revolving Facility Outstanding Amounts of all Lenders.

"Agreement" means this Credit Agreement.

"Applicable Rating" means (i) with respect to S&P, the rating designated by S&P as its corporate credit rating of the Borrower, and (ii) with respect to Fitch, the rating designated by Fitch as its rating of the Borrower's senior unsecured debt.

"Assignment and Assumption" means an assignment and assumption entered into by a Lender and an Eligible Assignee (with the consent of any party whose consent is required by Section 9.6), and accepted by the Administrative Agent, in substantially the form of Exhibit D or any other form approved by the Administrative Agent.

"Authorizing Order" means any order of any public utilities commission or any other regulatory body having jurisdiction over the Borrower, authorizing and/or restricting the indebtedness that may be created from time to time hereunder (whether on account of Advances or otherwise).

"**Bankruptcy Code**" means Title 11 of the United States Code, entitled "Bankruptcy," as amended.

"Base Rate" means, for any day, the rate of interest in effect for such day as publicly announced from time to time by the Administrative Agent as its "prime" or "base" rate (whether or not such rate is actually charged by the Administrative Agent), or if the Administrative Agent ceases to announce such a rate so designated, any similar successor rate designated by the Administrative Agent in its reasonable discretion. Any change in the Base Rate announced by the Administrative Agent shall take effect at the opening of business on the day specified in the public announcement of such change. Such rate is a reference rate and does not necessarily represent the lowest or best rate actually charged to any customer. Wells Fargo or any other Lender may make commercial loans or other loans at rates of interest at, above or below the Base Rate.

"Borrower" means MDU Resources Group, Inc., a Delaware corporation.

"Borrower Leverage Ratio" means the ratio of Funded Debt to Capitalization, determined with respect to the Borrower alone (excluding its Subsidiaries, but including any divisions of the Borrower not constituting separate Persons) as at the end of each fiscal quarter of the Borrower.

"Borrowing" means a borrowing under Article II consisting of Advances made to the Borrower at the same time by each of the Lenders severally.

"Business Day" means a day other than a Saturday, Sunday, United States national holiday or other day on which banks in Minnesota or New York are permitted or required by law to close. Whenever the context relates to a LIBOR Loan or the fixing of a LIBO Rate, "Business Day" means a day (i) that meets the foregoing definition, and (ii) on which dealings in U.S. dollar deposits are carried on in the London interbank eurodollar market.

"Capitalization" means, with respect to any Person as of any Covenant Compliance Date, (i) Funded Debt of that Person, plus (ii) shareholders' equity of that Person (excluding any non-cash gain or loss resulting from the requirements of Financial Accounting Standards Board Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities"), all determined in accordance with GAAP. In determining Capitalization for purposes of calculating the Borrower Leverage Ratio, Funded Debt and equity attributable to any Subsidiary shall be excluded.

"Capitalized Lease" means any lease that in accordance with GAAP should be capitalized on the balance sheet of the lessee thereunder or for which the amount of the asset and liability thereunder as if so capitalized should be disclosed in a note to such balance sheet. All obligations under any lease that is treated as an operating lease under GAAP but pursuant to which the lessee thereunder retains tax ownership of the leased property for federal income tax purposes shall be treated as a Capitalized Lease for purposes of this Agreement.

"**Cash Equivalents**" means, as to any Person, (a) securities issued or directly and fully guaranteed or insured by the United States or any agency or instrumentality thereof (but only so long as the full faith and credit of the United States is pledged in support thereof) having maturities of not more than 24 months from the date of acquisition; (b) securities issued by any state of the United States or any political subdivision of any such state or any public instrumentality thereof having maturities of not more than 24 months from the date of acquisition and having one of the two highest ratings from either S&P, Fitch, or Moody's Investors Service, Inc.; (c) domestic and Eurodollar certificates of deposit or time deposits or bankers' acceptances maturing within 24 months after the date of acquisition issued or guaranteed by or placed with, and money market and demand deposit accounts issued or offered by, any commercial bank organized under the laws of the United States or any state thereof or the District of Columbia, or any Canadian chartered bank, having combined capital and surplus of not less than $500,000,000; (d) repurchase obligations with a term of not more than thirty days for underlying securities of the types described in clause (a) and (b) of this definition entered into with any bank meeting the qualifications specified in clause (c) of this definition; (e) commercial paper issued by any commercial bank incorporated in the United States having capital and surplus in excess of $500,000,000 and commercial paper issued by any Person (other than a commercial bank) incorporated in the United States, which commercial paper has one of the two highest ratings from either S&P, Fitch or Moody's Investors Service, Inc., and in each case maturing not more than ninety days after the date of acquisition by such Person; and (f) investments in money market funds substantially all the assets of which are comprised of cash or securities of the types described in clauses (a) through (e) of this definition.

"Change in Law" means the occurrence, after the date of this Agreement, of any of the following: (a) the adoption or taking effect of any law, rule, regulation or treaty, (b) any change in any law, rule, regulation or treaty or in the administration, interpretation, implementation or application thereof by any Governmental Authority or (c) the making or issuance of any request, rule, guideline or directive (whether or not having the force of law) by any Governmental Authority; provided that notwithstanding anything herein to the contrary, (x) the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines or directives thereunder or issued in connection therewith and (y) all requests, rules, guidelines or directives promulgated by the Bank for International Settlements, the Basel Committee on Banking Supervision (or any successor or similar authority) or the United States or foreign regulatory authorities, in each case pursuant to Basel III, shall in each case be deemed to be a "Change in Law", regardless of the date enacted, adopted or issued.

"Change of Control" means, with respect to any corporation, either (i) the acquisition by any "person" or "group" (as those terms are used in Sections 13(d) and 14(d) of the Exchange Act) of beneficial ownership (as defined in Rules 13d-3 and 13d-5 of the Securities and Exchange Commission, except that a Person shall be deemed to have beneficial ownership of all securities that such Person has the right to acquire, whether such right is exercisable immediately or only after the passage of time), directly or indirectly, of 25% or more of the then-outstanding voting capital stock of such corporation; or (ii) a change in the composition of the board of directors of such corporation or any corporate parent of such corporation such that continuing directors cease to constitute more than 50% of such board of directors. As used in this definition, "continuing directors" means, as of any date, (i) those members of the board of directors of the applicable corporation who assumed office prior to such date, and (ii) those members of the board of directors of the applicable corporation who assumed office after such date and whose appointment or nomination for election by that corporation's shareholders was approved by a vote of at least 50% of the directors of such corporation in office immediately prior to such appointment or nomination.

"Code" means the Internal Revenue Code of 1986, and the regulations promulgated thereunder, as amended, reformed or otherwise modified from time to time.

"Commitment" means, with respect to each Lender, that Lender's Revolving Commitment.

"Compliance Certificate" means a certificate in substantially the form of Exhibit C, or such other form as the Borrower and the Required Lenders may from time to time agree upon in writing, executed by the chief financial officer of the Borrower, stating (i) that any financial statements delivered therewith have been prepared in accordance with GAAP (or, in the case of statements prepared pursuant to Section 5.1(b)(ii), in accordance with FERC Accounting Principles), subject to year-end adjustments, (ii) whether or not such officer has knowledge of the occurrence of any Default or Event of Default hereunder not theretofore reported and remedied and, if so, stating in reasonable detail the facts with respect thereto and (iii) all relevant facts in reasonable detail to evidence, and the computations as to, whether or not the Borrower is in compliance with the Financial Covenants.

"Consolidated Net Worth" means, at any time, the excess of total assets of the Borrower over total liabilities of the Borrower as of the last day of the fiscal quarter most recently then ended, determined on a consolidated basis in accordance with GAAP.

"Consolidated Total Leverage Ratio" means, as of any Covenant Compliance Date, the ratio of Funded Debt to Capitalization, determined on a consolidated basis with respect to the Borrower and all of its Subsidiaries.

"Covenant Compliance Date" means the last day of each fiscal quarter of the Borrower.

"Credit Exposure" means, with respect to any Lender at any time, (i) such Lender's Revolving Commitment (whether used or unused) at such time, or (ii) if the Revolving Commitments have terminated in their entirety, the aggregate outstanding principal amount of its Notes at such time.

"Credit Extension" means the making of any Advance, or the conversion to or continuation of any LIBOR Loan.

"Debtor Relief Laws" means the United States Bankruptcy Code and all other liquidation, conservatorship, bankruptcy, assignment for the benefit of creditors, moratorium, rearrangement, receivership, insolvency, reorganization, or similar debtor relief laws of the United States or other applicable jurisdictions from time to time in effect.

"Default" means an event that, with the giving of notice, the passage of time or both, would constitute an Event of Default.

"Default Rate" has the meaning specified in Section 2.6(c).

"Defaulting Lender" means, subject to Section 2.24(b), any Lender that (a) has failed to (i) fund all or any portion of its Loans within two Business Days of the date such Loans were required to be funded hereunder unless such Lender notifies the Administrative Agent and the Borrower in writing that such failure is the result of such Lender's determination that one or more conditions precedent to funding (each of which conditions precedent, together with any applicable default, shall be specifically identified in such writing) has not been satisfied, or (ii) pay to the Administrative Agent or any other Lender any other amount required to be paid by it hereunder within two Business Days of the date when due, (b) has notified the Borrower or the Administrative Agent in writing that it does not intend to comply with its funding obligations hereunder, or has made a public statement to that effect (unless such writing or public statement relates to such Lender's obligation to fund a Loan hereunder and states that such position is based on such Lender's determination that a condition precedent to funding (which condition precedent, together with any applicable default, shall be specifically identified in such writing or public statement) cannot be satisfied), (c) has failed, within three Business Days after written request by the Administrative Agent or the Borrower, to confirm in writing to the Administrative Agent and the Borrower that it will comply with its prospective funding obligations hereunder (provided that such Lender shall cease to be a Defaulting Lender pursuant to this clause (c) upon receipt of such written confirmation by the Administrative Agent and the Borrower), or (d) has, or has a direct or indirect parent company that has, (i) become the subject of a proceeding under any Debtor Relief Law, or (ii) had appointed for it a receiver, custodian, conservator, trustee, administrator, assignee for the benefit of creditors or similar Person charged with reorganization or liquidation of its business or assets, including the Federal Deposit Insurance Corporation or any other state or federal regulatory authority acting in such a capacity; provided that a Lender shall not be a Defaulting Lender solely by virtue of the ownership or acquisition of any equity interest in that Lender or any direct or indirect parent company thereof by a Governmental Authority so long as such ownership interest does not result in or provide such Lender with immunity from the jurisdiction of courts within the United States or from the enforcement of judgments or writs of attachment on its assets or permit such Lender (or such Governmental Authority) to reject, repudiate, disavow or disaffirm any contracts or agreements made with such Lender. Any determination by the Administrative Agent that a Lender is a Defaulting Lender under clauses (a) through (d) above shall be conclusive and binding absent manifest error, and such Lender shall be deemed to be a Defaulting Lender (subject to Section 2.24(b)) upon delivery of written notice of such determination to the Borrower and each Lender.

"Distribution" means any payment made by the Borrower on account of any equity interest in the Borrower, including but not limited to any dividend and any payment in purchase, redemption or other retirement of any stock or membership interest.

"Eligible Assignee" means any Person that meets the requirements to be an assignee under Sections 9.6(b)(iv) and (v) (subject to such consents, if any, as may be required under Section 9.6(b)(ii)).

“Environmental Claim” means a material claim, however asserted, by any governmental authority or other Person alleging potential liability or responsibility for violation of any Environmental Law, or for release or injury to the environment.

“Environmental Law” means the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9601 et seq., the Resource Conservation and Recovery Act, 42 U.S.C. § 6901 et seq., the Hazardous Materials Transportation Act, 49 U.S.C. § 1802 et seq., the Toxic Substances Control Act, 15 U.S.C. § 2601 et seq., the Federal Water Pollution Control Act, 33 U.S.C. § 1252 et seq., the Clean Water Act, 33 U.S.C. § 1321 et seq., the Clean Air Act, 42 U.S.C. § 7401 et seq., and any other federal, state, county, municipal, local or other statute, law, ordinance or regulation which in each case relates to human health or the environment, all as may be from time to time amended.

“ERISA” means the Employee Retirement Income Security Act of 1974, as amended.

“ERISA Affiliate” means any trade or business (whether or not incorporated) that is, along with the Borrower, a member of a controlled group of corporations or a controlled group of trades or businesses, as described in sections 414(b) and 414(c), respectively, of the Code.

“ERISA Event” means (a) a Reportable Event with respect to a Pension Plan; (b) a withdrawal by the Borrower or any ERISA Affiliate from a Pension Plan subject to Section 4063 of ERISA during a plan year in which it was a substantial employer (as defined in Section 4001(a)(2) of ERISA) or a cessation of operations which is treated as such a withdrawal under Section 4062(e) of ERISA; (c) a complete or partial withdrawal by the Borrower or any ERISA Affiliate from a Multiemployer Plan or notification that a Multiemployer Plan is in reorganization (within the meaning of Section 4241 of ERISA), insolvent (within the meaning of Section 4245 of ERISA) or in “critical” status (within the meaning of Section 432 of the Code or Section 305 of ERISA); (d) the commencement of proceedings by the PBGC to terminate a Pension Plan; (e) a failure by the Borrower or any ERISA Affiliate to make required contributions to a Pension Plan or Multiemployer Plan, or the imposition of a lien in favor of a Pension Plan under Section 430(k) of the Code or Section 303(k) of ERISA; (f) an event or condition which might reasonably be expected to constitute grounds under Section 4042 of ERISA for the termination of, or the appointment of a trustee to administer, any Pension Plan or for the imposition of any liability under Section 4069 or 4212(c) of ERISA; (g) the imposition of any liability under Title IV of ERISA, other than PBGC premiums due but not delinquent under Section 4007 of ERISA, upon the Borrower or any ERISA Affiliate; (h) an application for a funding waiver pursuant to Section 412 of the Code or Section 302(c) of ERISA with respect to any Plan; or (i) a determination that a Plan is, or is reasonably expected to be, in “at risk” status (within the meaning of Section 430 of the Code or Section 303 of ERISA).

“ERISA Termination Event” means the filing of a notice of intent to terminate a Pension Plan, or the treatment of a plan amendment as the termination of a Pension Plan, under Section 4041, 4041A or 4042 of ERISA.

“Event of Default” has the meaning specified in Section 7.1.

“Exchange Act” means the Securities Exchange Act of 1934, as amended.

“Excluded Taxes” means, with respect to any Lender Party or any other recipient of any payment to be made by or on account of any obligation of the Borrower hereunder, (a) taxes imposed on or measured by its overall net income (however denominated), and franchise taxes imposed on it (in lieu of net income taxes), by the jurisdiction (or any political subdivision thereof) under the laws of which such recipient is organized or in which its principal office is located or, in the case of any Lender, in which its applicable lending office is located, (b) any branch profits taxes imposed by the United States of America or any similar tax imposed by any other jurisdiction in which the Borrower is located and (c) in the case of a Foreign Lender, any withholding tax (including withholding taxes imposed under FATCA) that is imposed on amounts payable to such Foreign Lender at the time such Foreign Lender becomes a party hereto (or designates a new lending office) or is attributable to such Foreign Lender's failure or inability (other than as a result of a Change in Law) to comply with Section 2.17(e), except to the extent that such Foreign Lender (or its assignor, if any) was entitled, at the time of designation of a new lending office (or assignment), to receive additional amounts from the Borrower with respect to such withholding tax pursuant to Section 2.17(a).

"Existing Credit Agreement" means the Credit Agreement dated June 21, 2005 among the Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders, as defined therein, together with all amendments, modifications and restatements thereof.

"Existing Credit Agreement Lender" means, with respect to any specified time prior to the date hereof, a Person that was a "Lender" under the Existing Credit Agreement as of such time.

"Existing Credit Facility" means the revolving credit facility arising under the Existing Credit Agreement.

"Facility" means the Revolving Facility.

"Facility Fee" has the meaning specified in Section 2.10(a).

"Facility Fee Rate" means a percentage, determined as set forth in Section 2.5.

"FATCA" means Sections 1471 through 1474 of the Code, as of the date of this Agreement, and any current or future regulations or official interpretations thereof.

"Federal Funds Rate" means at any time an interest rate per annum equal to the weighted average of the rates for overnight federal funds transactions with members of the Federal Reserve System arranged by federal funds brokers, as published for such day by the Federal Reserve Bank of New York, or, if such rate is not so published for any day which is a Business Day, the average of the quotations for such day for such transactions received by the Administrative Agent from three federal funds brokers of recognized standing selected by it, it being understood that the Federal Funds Rate for any day which is not a Business Day shall be the Federal Funds Rate for the next preceding Business Day.

"Fee Letters" means (i) the Fee Letter dated April 4, 2011 between the Administrative Agent, Wells Fargo Securities, LLC and the Borrower, (ii) the Fee Letter dated April 4, 2011 between Union Bank, N.A. and the Borrower, and (iii) any separate agreements between the Borrower and the Administrative Agent after the date hereof that set forth the terms of fees to be paid by the Borrower to the Administrative Agent for the Administrative Agent's own behalf or for the benefit of the Lenders, as more fully set forth therein.

"FERC Accounting Principles" means the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

"Financial Covenant" means any of the Borrower's obligations set forth in Sections 6.9 and 6.10.

"Fitch" means Fitch, Inc.

"Floating LIBO Rate" means, for any day, a rate equal to the Adjusted LIBO Rate with respect to a one-month Interest Period commencing on that day. For the purposes of this definition, the Adjusted LIBO Rate as of any day shall be determined using the Adjusted LIBO Rate as otherwise determined by the Administrative Agent in accordance with the definitions of "LIBO Rate" and "Adjusted LIBO Rate" hereunder, except that (x) if the day is a Business Day, such determination shall be made on such day (rather than two Business Days prior to the commencement of an Interest Period), and (y) if the day is not a Business Day, the Adjusted LIBO Rate for such day shall be the rate determined by the Administrative Agent pursuant to the preceding clause (x) for the most recent Business Day preceding such day.

"Foreign Lender" means any Lender that is organized under the laws of a jurisdiction other than the United States of America, any state thereof or the District of Columbia.

"Funded Debt" of any Person means (without duplication) (i) all indebtedness of such Person for borrowed money (which shall, in the case of the Borrower, include but not be limited to all indebtedness under this Agreement, all indebtedness arising under the Indenture, and all Subordinated Debt); (ii) indebtedness of such Person evidenced by bonds, notes or similar written instruments, whether or not representing obligations for borrowed money; (iii) all liabilities required to appear on such Person's balance sheet with respect to Capitalized Lease obligations of such Person; (iv) all indebtedness secured by a Lien on any property owned by such Person, whether or not such indebtedness has been assumed by such Person or is nonrecourse to such Person; (v) the face amount of all letters of credit and bankers' acceptances issued for the account of such Person, and without duplication, all drafts drawn thereunder; (vi) all obligations of such Person with respect to leases constituting part of a sale and leaseback arrangement; (vii) all net obligations of such Person under interest rate agreements or currency agreements; and (viii) guaranty obligations of such Person with respect to indebtedness for borrowed money of another Person (including affiliates).

"GAAP" means generally accepted accounting principles as in effect from time to time applied on a basis consistent with the accounting practices applied in the financial statements of the Borrower and its Subsidiaries referred to in Section 4.5; provided that if the Borrower adopts any GAAP Change (as defined below), then unless and until the Borrower, the Administrative Agent and the Required Lenders agree to adjustments to the terms hereof to reflect such GAAP Change, all Financial Covenants, standards and terms in this Agreement shall continue to be determined as if such GAAP Change had not been implemented. As used in this definition, **"GAAP Change"** refers to any change in accounting principles required or permitted by any promulgation of the Financial Accounting Standards Board or, if applicable, the Securities Exchange Commission, and shall include the adoption or implementation of the International Financial Reporting Standards promulgated by the International Accounting Standards Board.

"Governmental Authority" means the government of the United States of America or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supra-national bodies such as the European Union or the European Central Bank).

"Hazardous Substance" means any asbestos, urea-formaldehyde, polychlorinated biphenyls, nuclear fuel or material, chemical waste, radioactive material, explosives, known carcinogens, petroleum products and by-products and other dangerous, toxic or hazardous pollutants, contaminants, chemicals, materials or substances listed or identified in, or regulated by, any Environmental Laws.

"Hedging Arrangement" means any agreement with respect to rate swap transactions, basis swaps, credit derivative transactions, forward rate transactions, commodity swaps, commodity options, forward commodity contracts, equity or equity index swaps or options, bond or bond price or bond index swaps or options or forward bond or forward bond price or forward bond index transactions, interest rate options, forward foreign exchange transactions, cap transactions, floor transactions, collar transactions, currency swap transactions, cross-currency rate swap transactions, currency options, spot contracts, or any other similar transactions or any combination of any of the foregoing (including any options to enter into any of the foregoing), whether or not any such transaction is governed by or subject to any master agreement.

"Hedging Obligations" means any debt, liability or other obligation owing with respect to any outstanding Hedging Arrangements. The amount of any Person's obligation in respect of any Hedging Obligation shall be deemed to be the incremental obligation that would be reflected in the financial statements of such Person in accordance with GAAP.

"Indemnified Taxes" means Taxes other than Excluded Taxes.

"Indenture" means the Indenture, dated as of December 15, 2003, executed by the Borrower and delivered to the Bank of New York Mellon, as trustee thereunder, as heretofore amended and supplemented and as hereafter amended and/or supplemented from time to time.

"Interest Payment Date" means (a) with respect to each ABR Loan, the last day of each calendar quarter, (b) with respect to each LIBOR Loan, the last day of the Interest Period applicable thereto (and, if such Interest Period is longer than 3 months, each day prior to the last day of such Interest Period that occurs at intervals of three months' duration after the first day of such Interest Period), and (c) with respect to each Loan, the Maturity Date with respect thereto.

"Interest Period" means, relative to any LIBOR Loan, the period beginning on (and including) the date on which such LIBOR Loan is made, or continued as, or converted into, a LIBOR Loan pursuant to Section 2.1, 2.2 or 2.3 and shall end on (but exclude) the day which numerically corresponds to such date 1, 2, 3 or 6 months thereafter (or, if such month has no numerically corresponding day, on the last Business Day of such month), as the Borrower may select in its relevant notice pursuant to Section 2.1, 2.2 or 2.3; provided, however, that:

(a) Unless otherwise agreed by the Administrative Agent, no more than 6 different Interest Periods may be outstanding at any one time with respect to the Revolving Facility.

(b) If an Interest Period would otherwise end on a day which is not a Business Day, such Interest Period shall end on the next following Business Day (unless such next following Business Day is the first Business Day of a month, in which case such Interest Period shall end on the next preceding Business Day).

(c) No Interest Period may end later than the Maturity Date.

"Lender Hedge Counterparty" means any Person who was a Lender or an Affiliate of a Lender (or was an Existing Credit Agreement Lender or an Affiliate of such a Person) at the time such Person entered in to a Hedging Arrangement with the Borrower.

"Lender Parties" means, collectively, the Administrative Agent and the Lenders.

"Lenders" means Wells Fargo, acting on its own behalf and not as Administrative Agent, each of the undersigned lenders, and any financial institution that becomes a Lender pursuant to Section 2.14 or 9.6(b), collectively.

"Level Status" means Level I, Level II, Level III, Level IV or Level V, each as determined pursuant to Section 2.5.

"LIBO Rate" means, with respect to an Interest Period, (a) the rate per annum determined by the Administrative Agent as of approximately 11:00 a.m. London time on the date 2 Business Days before the commencement of such Interest Period by reference to the British Bankers' Association Interest Settlement Rates for deposits in dollars offered on the London interbank dollar market for a period corresponding to the term of such Interest Period and in an amount comparable to the aggregate amount of the relevant Loan (as displayed in the Bloomberg Financial Market System or any successor thereto or any other service selected by the Administrative Agent that has been nominated by the British Bankers' Association as an authorized information vendor for the purpose of displaying such rates), or (b) if such rate cannot be determined, the rate per annum equal to the rate determined by the Administrative Agent in accordance with Section 2.4 to be a rate at which U.S. dollar deposits are offered to major banks in the London interbank eurodollar market for funds to be made available on the first day of such Interest Period and maturing at the end of such Interest Period.

"LIBOR Borrowing" means any Borrowing consisting of LIBOR Loans.

"LIBOR Loan" means any Loan that bears interest at a rate determined by reference to a LIBO Rate, excluding any ABR Loan.

"Lien" means any mortgage, deed of trust, lien, pledge, security interest or other charge or encumbrance, of any kind whatsoever, including but not limited to the interest of the lessor or titleholder under any Capitalized Lease, title retention contract or similar agreement.

"Loan" means a designated portion of outstanding principal indebtedness under a Facility.

"Loan Documents" means this Agreement, the Notes and the Fee Letters.

"Margin" means, with respect to computation of the applicable interest rate on Loans under the Revolving Facility, or the Facility Fee, as the case may be, the applicable increment so designated as determined in accordance with Section 2.5.

"Material Adverse Effect" means a material adverse effect on (i) the condition (financial or otherwise), properties, or operations of the Borrower, (ii) the ability of the Borrower to perform its obligations under the Loan Documents, or (iii) the validity or enforceability of any of the Loan Documents or the rights or remedies of the Administrative Agent or any Lender thereunder.

"Maturity Date" means May 26, 2015.

“Maximum Aggregate Revolving Facility Amount” means $150,000,000, unless said amount is reduced pursuant to Section 2.13, in which event it means the amount to which said amount is reduced.

“Multiemployer Plan” means a “multiemployer plan” (within the meaning of Section 4001(a)(3) of ERISA) to which the Borrower or any ERISA Affiliate makes, is making, or is obligated to make contributions or, during the preceding three calendar years, has made, or been obligated to make, contributions.

“Non-Defaulting Lender” means, at any time, a Lender that is not a Defaulting Lender at such time.

“Note” means a Revolving Note.

“Obligations” means each and every debt, liability and other obligation of every type and description arising under or in connection with any of the Loan Documents which the Borrower may now or at any time hereafter owe to any Lender Party, whether such debt, liability or obligation now exists or is hereafter created or incurred, whether it is direct or indirect, due or to become due, absolute or contingent, primary or secondary, liquidated or unliquidated, or sole, joint, several or joint and several, and including specifically, but not limited to, all indebtedness, liabilities and obligations of the Borrower arising under or evidenced by the Notes, excluding, however, any debt, liability or obligation due or owing to any Lender which has not been issued pursuant to any of the Loan Documents or is otherwise expressly contemplated therein.

“Other Taxes” means all present or future stamp or documentary taxes or any other excise or property taxes, charges or similar levies arising from any payment made hereunder or under any other Loan Document or from the execution, delivery or enforcement of, or otherwise with respect to, this Agreement or any other Loan Document.

“PBGC” means the Pension Benefit Guaranty Corporation.

“Pension Plan” means a pension plan (as defined in Section 3(2) of ERISA) subject to Title IV of ERISA or Section 412 of the Code or Section 302 of ERISA, which the Borrower or any ERISA Affiliate sponsors, maintains, or to which it makes, is making, or is obligated to make contributions, or in the case of a multiple employer plan (as described in Section 4064(a) of ERISA) has made contributions at any time during the immediately preceding five (5) plan years but excluding any Multiemployer Plan.

“Percentage” means, with respect to each Lender, the ratio of (i) that Lender’s Credit Exposure, to (ii) the aggregate Credit Exposure of all of the Lenders.

“Person” means any individual, corporation, partnership, limited liability company, joint venture, association, joint-stock company, trust, unincorporated organization or government or any agency or political subdivision thereof.

“Plan” means an employee benefit plan (as defined in Section 3(3) of ERISA) which the Borrower or any ERISA Affiliate sponsors or maintains or to which the Borrower or any ERISA Affiliate makes, is making, or is obligated to make contributions and includes any Pension Plan but excluding any Multiemployer Plan.

“Principal Payment Date” means, with respect to any Loan, the earliest of (i) the last day of the Interest Period applicable thereto, (ii) the first Business Day preceding each anniversary hereof, and (iii) the Maturity Date.

"Rating Agencies" means Fitch and S&P, collectively.

"Register" has the meaning specified in Section 9.6(c).

"Related Parties" means, with respect to any Person, such Person's Affiliates and the partners, directors, officers, employees, agents, trustees, administrators, managers, advisors and representatives of such Person and of such Person's Affiliates.

"Reportable Event" means any of the events set forth in Section 4043(c) of ERISA or the regulations thereunder, other than any such event for which the 30-day notice requirement under ERISA has been waived in regulations issued by the PBGC.

"Required Lenders" means one or more Lenders having an aggregate Percentage in excess of 50%; provided, however, that if any Lender is a Defaulting Lender at the time of determination, the Percentage of such Defaulting Lender shall be excluded from the determination of Required Lenders.

"Revolving Advance" means a loan of funds by a Lender to the Borrower under the Revolving Facility, including both ABR Loans and LIBOR Loans made thereunder.

"Revolving Borrowing" means a Borrowing consisting of a Revolving Advance by each of the Lenders.

"Revolving Commitment" means, with respect to each Lender, (i) the amount so designated opposite such Lender's name on Exhibit A, as such amount may be adjusted pursuant to Section 2.13 or 2.14 and plus or minus any such amount assumed or assigned pursuant to any Assignment and Assumption, or (ii) as the context may require, the obligation of such Lender to make Revolving Advances under Section 2.1.

"Revolving Commitment Termination Date" means the earlier of (a) the Maturity Date and (b) the date on which the Revolving Commitments are terminated pursuant to Section 2.13 or 7.2 or reduced to zero pursuant to Section 2.13.

"Revolving Facility" means the revolving credit facility being made available to the Borrower by the Lenders pursuant to Section 2.1.

"Revolving Facility Outstanding Amount" means, as of the date of determination with respect to any Lender, the aggregate principal amount of all outstanding Revolving Advances made by that Lender.

"Revolving Lender" means any Lender with a Revolving Commitment.

"Revolving Loan" means a Loan under the Revolving Facility.

"Revolving Note" means a promissory note of the Borrower payable to a Lender in the amount of such Lender's Revolving Commitment, in substantially the form of Exhibit B, as such promissory note may be amended, extended or otherwise modified from time to time, and including each other promissory note accepted from time to time in substitution therefor or in renewal thereof.

"Revolving Percentage" means, with respect to a Revolving Lender, such Revolving Lender's Percentage of the Revolving Facility.

"S&P" means Standard & Poor's Ratings Group, a division of McGraw-Hill Companies.

"Solvent" means as to any Person at any time (a) the fair value of the property of such Person is greater than the amount of such Person's liabilities (including the probable liability of such Person on disputed, contingent and unliquidated liabilities) as such value is established and liabilities evaluated for purposes of Section 101(32) of the Bankruptcy Code; (b) the present fair saleable value of the property of such Person is not less than the amount that will be required to pay the probable liability of such Person on its debts as they become absolute and matured; (c) such Person is able to realize upon its property and pay its debts and other liabilities (including the probable liability of such Person on disputed, contingent and unliquidated liabilities) as they mature in the normal course of business; (d) such Person does not intend to, and does not believe that it will, incur debts or liabilities beyond such Person's ability to pay as such debts and liabilities mature; and (e) such Person is not engaged in business or a transaction, and is not about to engage in business or a transaction, for which such Person's property would constitute unreasonably small capital.

"Subordinated Debt" means all indebtedness and other obligations of the Borrower which are subordinated in right of payment to all indebtedness of the Borrower to any Lender, on terms that have been approved in writing by the Required Lenders and that have been noted by appropriate legend on all instruments evidencing the Subordinated Debt.

"Subsidiary" of a Person means any corporation, association, partnership, limited liability company, joint venture or other business entity of which more than 50% of the voting stock, membership interests or other equity interests (in the case of Persons other than corporations), is owned or controlled directly or indirectly by the Person, by one of more of the Subsidiaries of the Person, or by a combination thereof. Unless the context otherwise clearly requires, references herein to a "Subsidiary" refer to a Subsidiary of the Borrower.

"Taxes" means all present or future taxes, levies, imposts, duties, deductions, withholdings, assessments, fees or other charges imposed by any Governmental Authority, including any interest, additions to tax or penalties applicable thereto.

"Unfunded Pension Liability" means the excess of the present value of all benefits accrued under a Pension Plan as of the valuation date for the plan year in which the determination is being made over the value of the assets of the Pension Plan as of such valuation date, each as determined using the applicable actuarial and valuation assumptions under Section 430 of the Code and Section 303 of ERISA.

"Wells Fargo" means Wells Fargo Bank, National Association, a national banking association and a party to this Agreement.

Section 1.2 Rules of Construction

For all purposes of this Agreement, except as otherwise expressly provided or unless the context otherwise requires:

(a) The terms defined in this Article have the meanings assigned to them in this Article, and include the plural as well as the singular.

(b) All accounting terms not otherwise defined herein have the meanings assigned to them in accordance with GAAP.

(c) References to documents (including this Agreement) shall be deemed to include all subsequent amendments and other modifications thereto and restatements thereof, but only to the extent such amendments, modifications and restatements are not prohibited by the terms of any Loan Document.

(d) The words "include", "includes" and "including" shall be deemed to be followed by the phrase "without limitation".

(e) All references to times of day in this Agreement shall be references to Minneapolis, Minnesota time unless otherwise specifically provided.

ARTICLE II
Amount and Terms of the Credit Facilities

Section 2.1 Revolving Facility.

(a) *Revolving Commitments.* Each Revolving Lender agrees, on the terms and subject to the conditions herein set forth, to make Revolving Advances to the Borrower from time to time during the period from the date hereof to and including the Revolving Commitment Termination Date, in an aggregate amount at any time outstanding not to exceed such Revolving Lender's Revolving Percentage of each Borrowing from time to time requested by the Borrower under the Revolving Facility; provided, however, that no Revolving Lender's Revolving Facility Outstanding Amount shall at any time exceed such Revolving Lender's Revolving Commitment. Within the above limits, the Borrower may obtain Revolving Advances, prepay Revolving Advances in accordance with the terms hereof and reborrow Revolving Advances in accordance with the applicable terms and conditions of this Agreement.

(b) *Revolving Borrowing Procedures.* Each Revolving Borrowing shall be funded by the Revolving Lenders as either an ABR Borrowing or a LIBOR Borrowing, as the Borrower shall specify in the related notice of proposed Borrowing. ABR Loans and LIBOR Loans may be outstanding at the same time. The principal amount of any Revolving Borrowing shall be in an amount equal to (i) $1,000,000 or a higher integral multiple of $500,000 if such Borrowing is funded as an ABR Borrowing, and (ii) $5,000,000 or a higher integral multiple of $1,000,000 if such Borrowing is funded as a LIBOR Borrowing. The Borrower shall give notice to the Administrative Agent of each proposed Revolving Borrowing not later than 12:00 noon on a Business Day that, in the case of an ABR Borrowing, is the proposed date of such Borrowing or, in the case of a Borrowing that is to bear interest initially at an Adjusted LIBO Rate, is at least 3 Business Days prior to the proposed date of such Borrowing. Each such notice shall be effective upon receipt by the Administrative Agent, shall be provided in writing or in such other manner as the Administrative Agent and the Borrower may agree (to be confirmed in writing by the Borrower if so requested by the Administrative Agent), and shall specify whether the Borrowing is to be an ABR Borrowing or a LIBOR Borrowing and, in the case of a LIBOR Borrowing, shall specify the Interest Period to be applicable thereto. Promptly upon receipt of such notice (but in no event later than 1:00 p.m. with respect to an ABR Borrowing, and the close of business, with respect to a LIBOR Borrowing, in each case on the Business Day of receipt of such notice), the Administrative Agent shall advise each Lender of the proposed Borrowing. Subject to satisfaction of the conditions precedent set forth in Article III with respect to such Borrowing, at or before 1:00 p.m. on the date of the requested Borrowing, each Revolving Lender shall provide the Administrative Agent at the principal office of the Administrative Agent in Charlotte, North Carolina (or such other office as the Administrative Agent may designate), with immediately available funds covering such Revolving Lender's Revolving Percentage of such Borrowing. The

Administrative Agent shall pay over proceeds of such Borrowing to the Borrower, in immediately available funds, prior to the close of business on the date of the requested Borrowing.

(c) *Limitation.* Notwithstanding any other provision of this Agreement to the contrary, no Borrowing shall be effected on any anniversary of this Agreement.

Section 2.2 Converting ABR Loans to LIBOR Loans; Procedures.

So long as no Default or Event of Default has occurred and is continuing, the Borrower may convert all or any part of any outstanding ABR Loan into a LIBOR Loan by giving notice to the Administrative Agent of such conversion not later than 9:00 a.m. on a Business Day that is at least 2 Business Days prior to the date of the requested conversion. Each such notice shall be irrevocable, shall be effective upon receipt by the Administrative Agent, shall be provided in writing or in such other manner as the Administrative Agent and the Borrower may agree (to be confirmed in writing by the Borrower if so requested by the Administrative Agent), shall specify the date and amount of such conversion, the total amount of the Loan to be so converted and the Interest Period therefor. Each conversion of a Loan shall be on a Business Day, and the aggregate amount of each such conversion of an ABR Loan to a LIBOR Loan shall be in an amount equal to $5,000,000 or a higher integral multiple of $1,000,000. The Administrative Agent shall promptly (but in no event later than the close of business on the day received) forward such notice to the applicable Lenders.

Section 2.3 Procedures at End of an Interest Period.

Unless the Borrower requests a new LIBOR Loan in accordance with the procedures set forth below, or prepays the principal of an outstanding LIBOR Loan at the expiration of an Interest Period, each Lender shall automatically and without request of the Borrower convert each LIBOR Loan to an ABR Loan on the last day of the relevant Interest Period. So long as no Default or Event of Default has occurred and is continuing, the Borrower may cause all or any part of any outstanding LIBOR Loan to continue as a LIBOR Loan after the end of the then applicable Interest Period by notifying the Administrative Agent not later than 9:00 a.m. on a Business Day that is at least 2 Business Days prior to the first day of the new Interest Period. Each such notice shall be irrevocable, effective when received by the Administrative Agents, shall be provided in writing or in such other manner as the Administrative Agent and the Borrower may agree (to be confirmed in writing by the Borrower if so requested by the Administrative Agent) and shall specify the first day of the applicable Interest Period, the amount of the expiring LIBOR Loan to be continued and the Interest Period therefor. The Administrative Agent shall promptly (but in no event later than the close of business on the day received) forward such notice to the applicable Lenders. Each new Interest Period shall begin on a Business Day and the amount of each LIBOR Loan shall be in an amount equal to $5,000,000 or a higher integral multiple of $1,000,000.

Section 2.4 Setting and Notice of Rates.

The applicable LIBO Rate for each Interest Period shall be determined by the Administrative Agent on the second Business Day prior to the beginning of such Interest Period, whereupon notice thereof (which may be by telephone) shall be given by the Administrative Agent to the Borrower and each Lender. Each such determination of the applicable LIBO Rate shall be conclusive and binding upon the parties hereto, in the absence of demonstrable error. The Administrative Agent, upon written request of the Borrower or any Lender, shall deliver to the Borrower or such requesting Lender a statement showing the computations used by the Administrative Agent in determining the applicable LIBO Rate hereunder.

Section 2.5 Level Status, Margins and Fee Rates.

(a) The Borrower's Level Status shall be determined on the basis of the Applicable Ratings established by the Rating Agencies, in accordance with the following table:

	Level I	Level II	Level III	Level IV	Level V
S&P	A or better	A- or better, but less than A	BBB+ or better, but less than A-	BBB or better, but less than BBB+	Less than BBB
Fitch	A or better	A- or better, but less than A	BBB+ or better, but less than A-	BBB or better, but less than BBB+	Less than BBB

(b) In making the determinations under paragraph (a):

(i) If any of the Rating Agencies changes the meaning or designation for its Applicable Ratings referenced in paragraph (a), the criteria for Level Status in the table in paragraph (a) shall be adjusted in such manner as the Required Lenders may reasonably determine to correspond with the applicable rating designations used by the applicable Rating Agency in effect on the date hereof.

(ii) If the Rating Agencies' Applicable Ratings are not in the same column above, the Borrower's Level Status shall be determined as follows:

(A) If the Applicable Ratings provided by the Rating Agencies are in adjacent columns, the Borrower's Level Status shall be based on the leftmost of the columns.

(B) If the Applicable Ratings provided by the Rating Agencies are separated by one or more columns, the Borrower's Level Status shall be based on the column to the immediate right of the leftmost applicable column.

Notwithstanding the foregoing, if the Applicable Rating established by either of the Rating Agencies is in the rightmost column above, the Borrower shall be deemed to be at Level Status V.

(iii) If one Rating Agency (but not both Rating Agencies) ceases to issue its Applicable Rating, the Borrower's Level Status shall be determined on the basis of the Applicable Rating of the remaining Rating Agency. If both Rating Agencies cease to establish their Applicable Ratings, the Borrower shall be deemed to be at Level Status V.

(c) The Margins at any time shall be determined from time to time on the basis of the Borrower's Level Status, in accordance with the following table:

	Level I	Level II	Level III	Level IV	Level V
ABR Loan Margin	0%	0.125%	0.200%	0.275%	0.475%
LIBOR Loan Margin	0.900%	1.125%	1.200%	1.275%	1.475%
Facility Fee Rate	0.100%	0.125%	0.175%	0.225%	0.275%

Section 2.6 Interest on Loans.

The Borrower will pay interest on the unpaid principal amount of each Loan for the period commencing on the date of this Agreement until the unpaid principal amount thereof is paid in full, in accordance with the following:

(a) *ABR Loans*. Subject to subsection (c) below, while any outstanding principal of a Loan constitutes an ABR Loan, the outstanding principal balance thereof shall bear interest at an annual rate at all times equal to the Adjusted Base Rate, plus the applicable Margin.

(b) *LIBOR Loans*. Subject to subsection (c) below, while any outstanding principal of a Loan constitutes a LIBOR Loan, the outstanding principal balance thereof shall bear interest at an annual rate equal to the Adjusted LIBO Rate established with respect to such LIBOR Loan in accordance with Section 2.1, 2.2 or 2.3, plus the applicable Margin.

(c) *Default Rate*. From and after the occurrence of any Event of Default under paragraph (a), (b), (g) or (h) of Section 7.1, and from and after written notice from the Administrative Agent (or the Required Lenders) to the Borrower following the occurrence of any other Event of Default, and continuing (in each case) thereafter until such Event of Default is cured or waived to the written satisfaction of the Required Lenders, the outstanding principal balance of each Loan shall bear interest, until paid in full, at an annual rate equal to the sum of (i) the interest rate otherwise in effect with respect to such outstanding principal and (ii) 200 basis points. In addition, all fees, indemnification obligations and other Obligations not paid when due hereunder shall bear interest, until paid in full, at an annual rate equal to the sum of (x) the Adjusted Base Rate, (y) the Margin then applicable to ABR Loans, and (z) 200 basis points (each rate described in this subsection (c) herein, a **"Default Rate"**).

(d) *Savings Clause*. Notwithstanding anything in this Section 2.6 to the contrary, at no time shall the Borrower be obligated or required to pay interest on any Obligation at a rate which could subject any Lender to either civil or criminal liability as a result of being in excess of the maximum interest rate which the Borrower is permitted by applicable law, including all applicable usury laws and Authorizing Orders. If, under the terms of this Agreement or any other Loan Document, the Borrower is at any time required or obligated to pay interest on any Obligation at a rate in excess of such maximum rate, the applicable interest rate shall be deemed to be immediately reduced to such maximum rate and all previous payments in excess of the maximum rate shall be deemed to have been payments in reduction of principal and not on account of any interest thereon due hereunder. All sums paid or agreed to be paid to a Lender for the use, forbearance or retention of any Obligation, shall, to the extent permitted by applicable law, be amortized, prorated, allocated and spread throughout the full stated term of the Obligation to which such payment applies until payment in full so that the rate or amount of interest on account of any such Obligation does not exceed the maximum lawful rate of interest from time to time in effect and applicable to such Obligation for so long as the Obligation is outstanding.

Section 2.7 Obligation to Repay Advances; Representations.

The Borrower shall be obligated to repay all Advances under this Article II notwithstanding the failure of the Administrative Agent to receive from the Borrower any written request therefor or written confirmation thereof and notwithstanding the fact that the Person requesting the same was not in fact authorized to do so. Any request for a Credit Extension, whether written, telephonic, telecopy or otherwise, shall be deemed to be a representation by the Borrower that the statements set forth in Section 3.2 are correct as of the time of the request.

Section 2.8 Scheduled Payments; Mandatory Prepayments; Evidence of Obligations.

(a) *Interest.* The Borrower shall pay accrued but unpaid interest on each Loan on each Interest Payment Date with respect to that Loan.

(b) *Revolving Facility Principal*. The Borrower shall pay the principal balance of all Revolving Borrowings then outstanding in full on each Principal Payment Date.

(c) *Maintenance of Records*. Each Lender shall maintain in accordance with its usual practice records evidencing the indebtedness of the Borrower to such Lender resulting from the Advances made by such Lender, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder. The Administrative Agent shall maintain in accordance with its usual practice the Register and such other records as it deems appropriate in which it shall record (i) the amount of each Advance hereunder, (ii) the amount of each Loan hereunder and, if applicable, the Interest Period with respect thereto, (iii) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder, and (iv) the amount of any sum received by the Administrative Agent hereunder for the account of the Lenders and each Lender's share thereof. The entries made in the records maintained pursuant to this paragraph (c) shall be *prima facie* evidence of the matters recorded therein; provided that the failure of any Lender or the Administrative Agent to maintain such records or any error therein shall not in any manner affect the obligation of a Borrower to repay the Obligations in accordance with the terms of this Agreement.

(d) *Promissory Notes Optional*. The Borrower's obligation to repay the principal of and interest on the Advances made by each Lender shall be evidenced in the Register and shall, if requested by such Lender, also be evidenced by a Revolving Note, duly executed and delivered by the Borrower, with blanks appropriately completed, with respect to Revolving Advances made by such Lender.

Section 2.9 Computation of Interest and Fees.

Interest accruing on the Loans, and all Facility Fees and other fees described in Section 2.10, shall be computed on the basis of the actual number of days elapsed in a year of 360 days; provided, however, that interest accruing from time to time on ABR Loans bearing interest determined by reference to the Base Rate shall be computed on the basis of the actual number of days elapsed in a year of 365 or 366 days, as the case may be.

Section 2.10 Fees.

(a) *Facility Fee*. The Borrower shall pay to the Administrative Agent, for the ratable benefit of the Lenders, a facility fee (the **"Facility Fee"**) determined at an annual rate equal to the then-applicable Facility Fee Rate applied to the average Aggregate Revolving Commitment Amount (whether or not used). The Facility Fee shall be due and payable quarterly in arrears on the last day of each calendar quarter, and on the Maturity Date. The Facility Fee shall accrue at all times, including at any time during which any condition in Article III has not been satisfied.

(b) *Fee Letters.* The Borrower shall pay all fees required to be paid pursuant to any Fee Letters.

(c) *Audit Fees*. Upon the occurrence of an Event of Default or at any time thereafter until such Event of Default is cured, the Borrower shall pay to the Administrative Agent, on written demand, reasonable fees charged by the Administrative Agent in connection with any audits or inspections by the Administrative Agent of any collateral or the operations or businesses of the Borrower, together with actual out-of-pocket costs and expenses incurred in conducting any such audit or inspection. All such audits and inspections shall be for the sole benefit of the Administrative Agent and the Lenders.

Section 2.11 Use of Proceeds.

The proceeds of the initial Borrowing hereunder shall be used to pay in full all obligations of the Borrower outstanding under the Existing Credit Facility, if any. The proceeds of each other Credit Extension (including the initial Borrowing, if no obligations described in the preceding sentence are outstanding on the date thereof) shall be used solely (i) to pay the Borrower's obligations under (A) its commercial paper program, (B) other short-term credit facilities, and (C) maturing long-term obligations, and (ii) for the general corporate purposes of the Borrower in the ordinary course of business.

Section 2.12 Voluntary Prepayments.

The Borrower from time to time may voluntarily prepay the Loans in whole or in part; provided, however, that (i) any prepayment of the Revolving Facility shall be applied against outstanding Revolving Loans of the Lenders participating in such facility pro rata according to each Lender's Percentage of the Revolving Facility, (ii) each prepayment of the Loans shall be made to the Administrative Agent not later than 1:00 p.m. on a Business Day, and funds received after that hour shall be deemed to have been received by the Administrative Agent on the next following Business Day, (iii) each partial prepayment of LIBOR Loans shall be accompanied by accrued interest on such partial prepayment through the date of prepayment and additional compensation, if any, calculated in accordance with Section 2.19, (iv) each partial prepayment of LIBOR Loans shall be in an aggregate amount equal to $5,000,000 or more and, after application of any such prepayment, shall not result in a LIBOR Loan remaining outstanding in an amount less than $5,000,000, and (v) each partial prepayment of ABR Loans shall be in an aggregate amount equal to $1,000,000 or a higher integral multiple of $500,000, unless (in either case) the aggregate outstanding balance of all Loans under the Facility being prepaid is less than such minimum Loan amount, in which event any such prepayment may be in such lesser amount. Unless otherwise provided in this Agreement or the other Loan Documents, prepayments from the Borrower of principal within any Facility above shall be applied first to the principal of ABR Loans and then to the principal of LIBOR Loans (and, among such LIBOR Loans, first to those with the earliest expiring Interest Periods).

Section 2.13 Voluntary Reduction or Termination of Aggregate Revolving Commitment Amount.

The Borrower, from time to time upon not less than 5 Business Days' prior written notice to the Administrative Agent, may permanently reduce the Aggregate Revolving Commitment Amount; provided, however, that no such reduction shall reduce the Aggregate Revolving Commitment Amount to an amount less than the Aggregate Revolving Facility Outstanding Amount. Any such voluntary reduction shall be pro rata as to all Revolving Commitments according to each Revolving Lender's Revolving Percentage and shall be in an aggregate amount equal to $5,000,000 or a higher integral multiple of $1,000,000. Each such reduction in the Aggregate Revolving Commitment Amount shall constitute a corresponding reduction in the Maximum Aggregate Revolving Facility Amount. The Borrower at any time prior to the Revolving Commitment Termination Date may terminate the Revolving Commitments by (i) providing to the Administrative Agent not less than 5 Business Days' prior written notice of its intention to so terminate the Revolving Commitments and (ii) making payment in full of all Revolving Loans and all other monetary Obligations. A notice of termination of the Revolving Commitments delivered by the Borrower may state that such notice is conditioned upon the effectiveness of other credit facilities, and such notice may be revoked by the Borrower (by notice to the Administrative Agent on or prior to the specified effective date) if such condition is not satisfied; provided, however, that the Borrower shall be responsible for all reasonable out-of-pocket costs and expenses of the Administrative Agent and the Lenders caused by the revocation of such notice of termination in accordance with Sections 2.19 and 9.4.

Section 2.14 Optional Increases of Aggregate Revolving Commitment Amount.

(a) *Request to Increase*. Following the date hereof, and provided no Event of Default has occurred and is continuing, the Borrower may, with the consent of and in coordination with the Administrative Agent and each Lender increasing its Revolving Commitment (including any Eligible Assignee that has not been a Lender but becomes a Lender in connection therewith) as to all of the matters set forth below in this Section 2.14, from time to time propose to increase the Aggregate Revolving Commitment Amount by increasing the Revolving Commitments of one or more Lenders or by obtaining a Revolving Commitment from an Eligible Assignee that will become a Lender. The aggregate principal amount of each increase to the Aggregate Revolving Commitment Amount made pursuant to this Section 2.14 (the amount of any such increase, the **"Increased Commitment Amount"**) shall be equal to an integral multiple of $5,000,000. No such increase shall cause the Aggregate Revolving Commitment Amount to exceed the Maximum Aggregate Revolving Facility Amount. No more than two increases in the Aggregate Revolving Commitment Amount may be effected pursuant to this Section 2.14. No Lender shall be obligated to increase its Revolving Commitment as a result of any such request by the Borrower, but no Lender (other than the Administrative Agent, in that capacity) shall have any right to object to the allocation of any Increased Commitment Amount among the other Lenders (including any Person who will become a Lender in connection therewith).

(b) *Conditions Precedent*. Any increase in the Aggregate Revolving Commitment Amount under this Section 2.14 shall become effective upon the receipt by the Administrative Agent of:

(i) An amendment, modification or joinder to this Agreement, duly signed by the Borrower, the Administrative Agent and each Lender whose Revolving Commitment will be increased and each other Lender or Eligible Assignee who has subscribed to provide a portion of the Increased Commitment Amount, modifying the definition of "Aggregate Revolving Commitment Amount" and setting forth the agreement of each Eligible Assignee to become a party to this

Agreement and to be bound by all the terms and provisions hereof. Any such amendment, modification or joinder may provide that interest or Facility Fees with respect to any Increased Commitment Amount will accrue at the rates set forth herein or at a higher rate.

(ii) Amendments and modifications, duly executed by the Borrower and the Administrative Agent, to any other Loan Documents reasonably requested by the Administrative Agent in relation to the Increased Commitment Amount, which amendments and modifications the Administrative Agent is hereby authorized to execute and deliver on behalf of the Lenders.

(iii) Notes, duly executed by the Borrower, as any Lender or Eligible Assignee may require.

(iv) Evidence of appropriate corporate authorization on the part of the Borrower with respect to the Increased Commitment Amount and the execution and delivery of the documents described in this Section 2.14.

(v) Such opinions of counsel for the Borrower and other assurances as the Administrative Agent may reasonably request.

(vi) Reimbursement of the Administrative Agent's out-of-pocket costs and expenses (including reasonable attorney's fees) incurred in connection therewith.

(c) *Adjustments.* On the effective date of any Increased Commitment Amount, the Borrower shall, in coordination with the Administrative Agent, repay the outstanding Advances of certain Lenders, and incur additional Advances from certain other Lenders, in each case to the extent necessary so that all of the Lenders participate in each outstanding Loan ratably on the basis of their respective Revolving Commitments (after giving effect to any increase in the Aggregate Revolving Commitment Amount pursuant to this Section 2.14). The Borrower shall be obligated to pay to the applicable Lenders any costs of the type referred to in Section 2.19 in connection with any such repayment.

(d) *Conflicts with Other Provisions.* This Section 2.14 shall supersede any provisions in Section 9.2 to the contrary.

Section 2.15 Payments Generally.

(a) *Making of Payments*. All payments of principal of and interest due hereunder shall be made to the Administrative Agent for the account of the applicable Lenders pro rata according to their respective Percentages of the applicable Facility. All payments of fees pursuant to Section 2.10 shall be made to the Administrative Agent for the account of the Administrative Agent or the Lenders, as specified in Section 2.10. All payments hereunder shall be made to the Administrative Agent at its office in Charlotte, North Carolina (or such other office as the Administrative Agent may designate) not later than 2:00 p.m. on the date due, in immediately available funds, without setoff or counterclaim, and funds received after that hour shall be deemed to have been received on the next following Business Day. The Borrower hereby authorizes the Administrative Agent to charge the Borrower's demand deposit account maintained with the Administrative Agent (or with any other Lender) for the amount of any Obligation on its due date, but the Administrative Agent's failure to so charge any such account shall in no way affect the obligation of the Borrower to make any such payment. The Administrative Agent shall remit to each Lender in immediately available funds on the same Business Day as received by the Administrative Agent its share of all such payments received by the Administrative Agent for the account of such Lender. All payments under Sections 2.16, 2.17 or 2.19 shall be made by the Borrower directly to the Lender entitled thereto.

(b) *Effect of Payments*. Each payment by the Borrower to the Administrative Agent for the account of any Lender pursuant to this Agreement shall be deemed to constitute payment by the Borrower directly to such Lender, provided, however, that in the event any such payment by the Borrower to the Administrative Agent is required to be returned to the Borrower for any reason whatsoever, then the Borrower's obligation to such Lender with respect to such payment shall be deemed to be automatically reinstated.

(c) *Assumed Payments*. Unless the Administrative Agent has been notified by a Lender or the Borrower prior to the date on which such Lender or the Borrower is scheduled to make payment to the Administrative Agent of (in the case of a Lender) the proceeds of an Advance to be made by it hereunder or (in the case of the Borrower) a payment to the Administrative Agent for the account of one or more of the Lenders hereunder (such payment by a Lender or the Borrower (as the case may be) being herein called a **"Required Payment"**), which notice shall be effective upon receipt, that it does not intend to make the Required Payment to the Administrative Agent, the Administrative Agent may assume that the Required Payment has been made and may (but shall not be required to), in reliance upon such assumption, make the amount thereof available to the intended recipient on such date and, if such Lender or the Borrower (as the case may be) has not in fact made the Required Payment to the Administrative Agent, the recipient of such payment shall, on demand, repay to the Administrative Agent the amount so made available together with interest thereon for each day during the period commencing on the date such amount was so made available by the Administrative Agent until the date the Administrative Agent recovers such amount at an annual rate (i) equal to the Federal Funds Rate for such day, in the case of a Required Payment owing by a Lender, or (ii) equal to the applicable rate of interest as provided in this Agreement, in the case of a Required Payment owing by the Borrower.

(d) *Due Date Extension*. Subject to subsection (b) of the definition of "Interest Period" with respect to LIBOR Loans, if any payment of principal of or interest on any Loan or any fees payable hereunder falls due on a day which is not a Business Day, then such due date shall be extended to the next following Business Day, and (in the case of principal) additional interest shall accrue and be payable for the period of such extension.

(e) *Application of Payments*. Except as otherwise provided herein (including as set forth in Section 7.4), (i) so long as no Default or Event of Default has occurred and is continuing hereunder, each payment received from the Borrower shall be applied to such Obligations as the Borrower shall specify by notice to be received by the Administrative Agent on or before the date of such payment; and (ii) in the absence of such notice and in any event during the continuance of any Default or Event of Default, payments received from the Borrower shall be applied, first, to payment of that portion of the Obligations then due and owing constituting fees, indemnities, expenses and other amounts, including attorney fees, payable to the Administrative Agent in its capacity as such; second, to pay fees then due and owing under Section 2.10; third, to pay interest then due and owing with respect to the Loans; fourth, to pay principal of the Revolving Loans; and fifth, to the payment of any other Obligations in such order as the Administrative Agent shall determine in its discretion.

Section 2.16 Increased Costs.

(a) *Increased Costs Generally*. If any Change in Law shall:

(i) impose, modify or deem applicable any reserve, special deposit, compulsory loan, insurance charge or similar requirement against assets of, deposits with or for the account of, or credit extended or participated in by, any Lender (except any reserve requirement reflected in the Adjusted LIBO Rate);

(ii) subject any Lender to any tax of any kind whatsoever with respect to this Agreement or any Loan made by it, or change the basis of taxation of payments to such Lender in respect thereof (except for Indemnified Taxes or Other Taxes covered by Section 2.17 and the imposition of, or any change in the rate of, any Excluded Tax payable by such Lender); or

(iii) impose on any Lender or the London interbank market any other condition, cost or expense affecting this Agreement or LIBOR Loans made by such Lender;

and the result of any of the foregoing shall be to increase the cost to such Lender of making or maintaining any LIBOR Loan (or of maintaining its obligation to make any such Loan), or to reduce the amount of any sum received or receivable by such Lender hereunder (whether of principal, interest or any other amount) then, upon request of such Lender, the Borrower will pay to such Lender such additional amount or amounts as will compensate such Lender for such additional costs incurred or reduction suffered.

(b) *Capital Requirements*. If any Lender determines that any Change in Law affecting such Lender or any lending office of such Lender or such Lender's holding company, if any, regarding capital requirements has or would have the effect of reducing the rate of return on such Lender's capital or on the capital of such Lender's holding company, if any, as a consequence of this Agreement, the Commitments of such Lender or the Loans made such Lender, to a level below that which such Lender or such Lender's holding company could have achieved but for such Change in Law (taking into consideration such Lender's policies and the policies of such Lender's holding company with respect to capital adequacy), then from time to time the Borrower will pay to such Lender such additional amount or amounts as will compensate such Lender or such Lender's holding company for any such reduction suffered.

(c) *Certificates for Reimbursement*. A certificate of a Lender setting forth the amount or amounts necessary to compensate such Lender or its holding company, as the case may be, as specified in paragraph (a) or (b) of this Section and delivered to the Borrower shall be conclusive absent demonstrable error. The Borrower shall pay such Lender the amount shown as due on any such certificate within 10 Business Days after receipt thereof.

(d) *Delay in Requests*. Failure or delay on the part of any Lender to demand compensation pursuant to this Section shall not constitute a waiver of such Lender's right to demand such compensation, provided that the Borrower shall not be required to compensate a Lender pursuant to this Section for any increased costs incurred or reductions suffered more than three months prior to the date that such Lender notifies the Borrower of the Change in Law giving rise to such increased costs or reductions and of such Lender's intention to claim compensation therefor (except that, if the Change in Law giving rise to such increased costs or reductions is retroactive, then the three-month period referred to above shall be extended to include the period of retroactive effect thereof).

Section 2.17 Taxes.

(a) *Payments Free of Taxes*. Any and all payments by or on account of any obligation of the Borrower hereunder or under any other Loan Document shall be made free and clear of and without reduction or withholding for any Indemnified Taxes or Other Taxes, provided that if the Borrower shall be required by applicable law to deduct any Indemnified Taxes (including any Other Taxes) from such payments, then (i) the sum payable shall be increased as necessary so that after making all required deductions (including deductions applicable to additional sums payable under this Section) the Lender Party entitled thereto receives an amount equal to the sum it would have received had no such deductions been made, (ii) the Borrower shall make such deductions, and (iii) the Borrower shall timely pay the full amount deducted to the relevant Governmental Authority in accordance with applicable law.

(b) *Payment of Other Taxes by the Borrower*. Without limiting the provisions of paragraph (a) above, the Borrower shall timely pay any Other Taxes to the relevant Governmental Authority in accordance with applicable law.

(c) *Indemnification by the Borrower*. The Borrower shall indemnify each Lender Party within 10 Business Days after demand therefor, for the full amount of any Indemnified Taxes or Other Taxes (including Indemnified Taxes or Other Taxes imposed or asserted on or attributable to amounts payable under this Section) paid by such Lender Party, and any penalties, interest and reasonable expenses arising therefrom or with respect thereto, whether or not such Indemnified Taxes or Other Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to the Borrower by a Lender Party (with a copy to the Administrative Agent) shall be conclusive absent manifest error.

(d) *Evidence of Payments*. As soon as practicable after any payment of Indemnified Taxes or Other Taxes by the Borrower to a Governmental Authority, the Borrower shall deliver to the Administrative Agent the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of the return reporting such payment or other evidence of such payment reasonably satisfactory to the Administrative Agent.

(e) *Status of Lenders*. Any Foreign Lender that is entitled to an exemption from or reduction of withholding tax under the law of the jurisdiction in which the Borrower is resident for tax purposes, or any treaty to which such jurisdiction is a party, with respect to payments hereunder or under any other Loan Document shall deliver to the Borrower (with a copy to the Administrative Agent), at the time or times prescribed by applicable law or reasonably requested by the Borrower or the Administrative Agent, such properly completed and executed documentation prescribed by applicable law as will permit such payments to be made without withholding or at a reduced rate of withholding. In addition, any Lender, if requested by the Borrower or the Administrative Agent, shall deliver such other documentation prescribed by applicable law or reasonably requested by the Borrower or the Administrative Agent as will enable the Borrower or the Administrative Agent to determine whether or not such Lender is subject to backup withholding or information reporting requirements.

(f) *Treatment of Certain Refunds*. If any Lender Party determines, in its sole discretion, that it has received a refund of any Taxes or Other Taxes as to which it has been indemnified by the Borrower or with respect to which the Borrower has paid additional amounts pursuant to this Section, it shall pay to the Borrower an amount equal to such refund (but only to the extent of indemnity payments made, or additional amounts paid, by the Borrower under this Section with respect to the Taxes or Other Taxes giving rise to such refund), net of all out-of-pocket expenses of such Lender Party and without interest (other than any interest paid by the relevant Governmental Authority with respect to such refund), provided that the Borrower, upon the request of a Lender Party will repay the amount paid over to the Borrower (plus any penalties, interest or other charges imposed by the relevant Governmental Authority) to such Lender Party in the event such Lender Party is required to repay such refund to such Governmental Authority. This paragraph shall not be construed to require any Lender Party to make available its tax returns (or any other information relating to its taxes that it deems confidential) to the Borrower or any other Person.

Section 2.18 Basis for Determining Interest Rate Inadequate or Unfair; Illegality.

If at any time:

(a) any Lender determines that deposits in U.S. dollars (in the applicable amounts) are not being offered in the London interbank eurodollar market; or

(b) any Lender otherwise determines that by reason of circumstances affecting the London interbank eurodollar market adequate and reasonable means do not exist for ascertaining a LIBO Rate; or

(c) any Lender determines that the Adjusted LIBO Rate as determined by the Administrative Agent will not adequately and fairly reflect the cost to that Lender of maintaining or funding its Loans, or that the making or funding of Loans based on the Adjusted LIBO Rate has become impracticable as a result of an event occurring after the date of this Agreement that in the opinion of that Lender materially affects such Loans; or

(d) any Change in Law or any change in the interpretation of applicable laws or regulations by any governmental authority, central bank, comparable agency or any other regulatory body charged with the interpretation, implementation or administration thereof, or compliance by a Lender with any request or directive (whether or not having the force of law) of any such authority, central bank, comparable agency or other regulatory body, should make it or, in the good faith judgment of the affected Lender, shall raise a substantial question as to whether it is unlawful for such Lender to make, maintain or fund LIBOR Loans,

then (i) the affected Lender shall promptly notify the Borrower and the Administrative Agent, (ii) the obligation of the affected Lender to make or continue any LIBOR Loan, or to convert any Loan into a LIBOR Loan shall, upon the effectiveness of such event, be suspended for the duration of such condition, (iii) for the duration of such condition, any notice by the Borrower pursuant to Section 2.1, 2.2 or 2.3 requesting the affected Lender to make any LIBOR Loan, to continue any LIBOR Loan or to convert any Revolving ABR Loan into a LIBOR Loan shall be construed as a request to make (or continue) such Loan as an ABR Loan, and (iv) at the option of such Lender, the Adjusted Base Rate shall be determined without reference to the Floating LIBO Rate.

Section 2.19 Loan Losses.

The Borrower hereby agrees that upon demand by any Lender (which demand shall be accompanied by a written statement setting forth the basis for the calculations of the amount being claimed) the Borrower will indemnify such Lender against any loss or expense which such Lender may have sustained or incurred (including any net loss or expense incurred by reason of the liquidation or reemployment of deposits or other funds acquired by such Lender to fund or maintain LIBOR Loans) or which such Lender may be deemed to have sustained or incurred, as reasonably determined by such Lender, (i) as a consequence of any failure by the Borrower to make any payment when due of any amount due hereunder in connection with any LIBOR Loans, (ii) due to any failure of the Borrower to borrow or convert any LIBOR Loans on a date specified therefor in a notice thereof or (iii) due to any payment or prepayment of any LIBOR Loan on a date other than the last day of the applicable Interest Period for such LIBOR Loan. For this purpose, all notices under Sections 2.1, 2.2 and 2.3 shall be deemed to be irrevocable.

Section 2.20 Right of Lenders to Fund through Other Offices.

Each Lender, if it so elects, may fulfill its agreements hereunder with respect to any LIBOR Loan by causing a foreign branch or affiliate of such Lender to make such LIBOR Loan; provided, that in such event the obligation of the Borrower to repay such LIBOR Loan shall nevertheless be to such Lender and such LIBOR Loan shall be deemed held by such Lender for the account of such branch or affiliate.

Section 2.21 Discretion of Lenders as to Manner of Loan.

Notwithstanding any provision of this Agreement to the contrary, each Lender shall be entitled to fund and maintain all or any part of its LIBOR Loans in any manner it deems fit, it being understood, however, that for the purposes of this Agreement (including Section 2.19 hereof) all determinations hereunder shall be made as if each Lender had actually funded and maintained each LIBOR Loan during each Interest Period for such LIBOR Loan through the purchase of deposits having a maturity corresponding to such Interest Period and bearing an interest rate equal to the appropriate Adjusted LIBO Rate for such Interest Period.

Section 2.22 Conclusiveness of Statements; Survival of Provisions; Limited Time for Claims.

Determinations and statements of a Lender pursuant to Section 2.16, 2.17, 2.18 or **2.19** shall be conclusive absent demonstrable error. Each Lender may use reasonable averaging and attribution methods in determining compensation pursuant to such Sections 2.16, 2.17 and 2.19 and the provisions of Sections 2.16, 2.17 and 2.19 shall survive termination of this Agreement.

Section 2.23 Nature of Lender Parties' Obligations.

The obligations of each Lender Party hereunder are the several obligations of such Lender Party, and no Lender Party shall be responsible for the obligations of any other Lender Party hereunder, nor will the failure by any Lender Party to perform any of its obligations hereunder relieve any other Lender Party from the performance of its obligations hereunder. Nothing contained in this Agreement, and no action taken by any Lender Party pursuant hereto or in connection herewith or pursuant to or in connection with the Loan Documents shall be deemed to constitute the Lender Parties as a partnership, association, joint venture, or other entity.

Section 2.24 Defaulting Lenders.

(a) *Defaulting Lender Adjustments*. Notwithstanding anything to the contrary contained in this Agreement, if any Lender becomes a Defaulting Lender, then, until such time as such Lender is no longer a Defaulting Lender, to the extent permitted by applicable law:

(i) *Waivers and Amendments*. Such Defaulting Lender's right to approve or disapprove any amendment, waiver or consent with respect to this Agreement shall be restricted as set forth in the definition of Required Lenders and Section 9.2.

(ii) *Defaulting Lender Waterfall*. Any payment of principal, interest, fees or other amounts received by the Administrative Agent for the account of such Defaulting Lender (whether voluntary or mandatory, at maturity, pursuant to Article VII or otherwise) or received by the Administrative Agent from a Defaulting Lender pursuant to Section 7.3 shall be applied at such time or times as may be determined by the Administrative Agent as follows: *first*, to the payment of any amounts owing by such Defaulting Lender to the Administrative Agent hereunder; *second*, as the Borrower may request (so long as no Default or Event of Default exists), to the funding of any Loan in respect of which such Defaulting Lender has failed to fund its portion thereof as required by this Agreement, as determined by the Administrative Agent; *third*, if so determined by the Administrative Agent and the Borrower, to be held in a deposit account and released pro rata in order to satisfy such Defaulting Lender's potential future funding obligations with respect to Loans under this Agreement; *fourth*, to the payment of any amounts owing to the Lenders as a result of any judgment of a court of competent jurisdiction obtained by any Lender against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement; *fifth*, so long as no Default or Event of Default exists, to the payment of any amounts owing to the Borrower as a result of any judgment of a court of competent jurisdiction obtained by the Borrower against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement; and *sixth,* to such Defaulting Lender or as otherwise directed by a court of competent jurisdiction; provided that if (x) such payment is a payment of the principal amount of any Loans in respect of which such Defaulting Lender has not fully funded its appropriate share, and (y) such Loans were made at a time when the conditions set forth in Section 3.2 were satisfied or waived, such payment shall be applied solely to pay the Loans of all Non-Defaulting Lenders on a pro rata basis prior to being applied to the payment of any Loans of such Defaulting Lender until such time as all Loans are held by the Lenders pro rata in accordance with the Commitments under the applicable Facility. Any payments, prepayments or other amounts paid or payable to a Defaulting Lender that are applied (or held) to pay amounts owed by a Defaulting Lender pursuant to this Section 2.24(a)(ii) shall be deemed paid to and redirected by such Defaulting Lender, and each Lender irrevocably consents hereto.

(iii) *Facility Fee*. Each Defaulting Lender shall be entitled to receive a Facility Fee for any period during which that Lender is a Defaulting Lender only to extent allocable to the sum of the outstanding principal amount of the Revolving Loans funded by it.

(b) *Defaulting Lender Cure*. If the Borrower and the Administrative Agent agree in writing that a Lender is no longer a Defaulting Lender, the Administrative Agent will so notify the parties hereto, whereupon as of the effective date specified in such notice and subject to any conditions set forth therein, that Lender will, to the extent applicable, purchase at par that portion of outstanding Loans of the other Lenders or take such other actions as the Administrative Agent may determine to be necessary to cause the Loans to be held pro rata by the Lenders in accordance with the Commitments under the applicable Facility, whereupon such Lender will cease to be a Defaulting Lender; provided that no adjustments will be made retroactively with respect to fees accrued or payments made by or on behalf of the Borrower while that Lender was a Defaulting Lender; and provided, further, that except to the extent otherwise expressly agreed by the affected parties, no change hereunder from Defaulting Lender to Lender will constitute a waiver or release of any claim of any party hereunder arising from that Lender's having been a Defaulting Lender.

ARTICLE III
Conditions Precedent

Section 3.1 Initial Conditions Precedent.

The obligation of the Lenders to effect any Borrowing is subject to the condition precedent that each Lender shall have received on or before the day of the first Borrowing all of the following, each dated (unless otherwise indicated) as of the date hereof, in form and substance satisfactory to each Lender:

(a) The Notes, properly executed on behalf of the Borrower.

(b) A certificate of the secretary of the Borrower (i) certifying that the execution, delivery and performance of the Loan Documents and other documents contemplated hereunder to which such corporation is a party have been duly approved by all necessary action of the Board of Directors of the Borrower, and attaching true and correct copies of the applicable resolutions granting such approval, (ii) certifying that attached to such certificate are true and correct copies of the articles of incorporation and bylaws of the Borrower and all Authorizing Orders, together with such copies, and (iii) certifying the names of the officers of the Borrower that are authorized to sign the Loan Documents and other documents contemplated hereunder, including requests for Borrowings, together with the true signatures of such officers. The Lenders may conclusively rely on such certificate until they shall receive a further certificate of the Secretary or Assistant Secretary of the Borrower canceling or amending the prior certificate and submitting the signatures of the officers named in such further certificate.

(c) Certificates of good standing of the Borrower, dated not more than ten days before such date.

(d) A signed copies of an opinion of Paul K. Sandness, general counsel for the Borrower, substantially in the form of Exhibit E-1, and the opinion of Cohen Tauber Spievack & Wagner P.C., special counsel to the Borrower, substantially in the form of Exhibit E-2, each addressed to the Lenders.

(e) All fees required to be paid as of the date hereof pursuant to this Agreement or any Fee Letter.

Section 3.2 Conditions Precedent to All Borrowings.

The obligation of the Lenders to effect any Borrowing shall be subject to the further conditions precedent that on the date of such Borrowing:

(a) the representations and warranties contained in Article IV (other than Section 4.6) are correct on and as of the date of such Borrowing as though made on and as of such date, except to the extent that such representations and warranties relate solely to an earlier date;

(b) the Borrower has delivered to the Administrative Agent an opinion in the form of Exhibit F hereto, duly executed by the general counsel or associate general counsel of the Borrower; and

(c) no event has occurred and is continuing, or would result from such Borrowing, which constitutes a Default or an Event of Default.

ARTICLE IV
Representations and Warranties

The Borrower represents and warrants to the Lenders as follows:

Section 4.1 Existence and Power.

The Borrower is a corporation duly incorporated, validly existing and in good standing under the laws of Delaware, and is duly licensed or qualified to transact business in all jurisdictions where the character of the property owned or leased or the nature of the business transacted by it makes such licensing or qualification necessary, except where the failure to be so licensed or qualified (i) will not permanently preclude the Borrower from maintaining any material action in any such jurisdiction even though such action arose in whole or in part during the period of such failure, and (ii) will not result in any other Material Adverse Effect. The Borrower has all requisite power and authority, corporate or otherwise, to conduct its business, to own its properties and to execute and deliver, and to perform all of its obligations under, the Loan Documents.

Section 4.2 Authorization of Credit Extensions; No Conflict as to Law or Agreements.

The execution, delivery and performance by the Borrower of the Loan Documents, and the borrowings from time to time hereunder, have been duly authorized by all necessary corporate action and by all necessary public utilities commissions and any other regulatory bodies having jurisdiction over the Borrower (except as noted in Schedule 4.2 to the Agreement with respect to Borrowings made after December 31, 2011), and do not and will not (i) require any consent or approval of the stockholders of the Borrower, or any authorization, consent or approval by any governmental department, commission, board, bureau, agency or instrumentality, domestic or foreign, other than Authorizing Orders set forth in Schedule 4.2 that (except as noted therein with respect to Borrowings made after December 31, 2011) have been obtained and copies of which have been delivered to the Administrative Agent pursuant to Section 3.1, (ii) violate any provision of any law, rule or regulation (including, without limitation, Regulation T, U or X of the Board of Governors of the Federal Reserve System) or of any order, writ, injunction or decree presently in effect having applicability to the Borrower or of the articles of incorporation or bylaws of the Borrower, (iii) result in a breach of or constitute a default under any indenture or loan or credit agreement or any other agreement, lease or instrument to which the Borrower is a party or by which it or its properties may be bound or affected, or (iv) result in, or require, the creation or imposition of any Lien or other charge or encumbrance of any nature (other than those in favor of the Administrative Agent to secure one or more of the Obligations) upon or with respect to any of the properties now owned or hereafter acquired by the Borrower.

Section 4.3 Legal Agreements.

This Agreement and the other Loan Documents constitute the legal, valid and binding obligations of the Borrower enforceable against the Borrower in accordance with their respective terms, except to the extent that such enforcement may be limited by bankruptcy, insolvency or similar laws affecting the enforcement of creditors' rights generally or by general equitable principles.

Section 4.4 Subsidiaries.

Schedule 4.4 hereto is a complete and correct list of all present Subsidiaries and of the percentage of the ownership of the Borrower or any other Subsidiary in each case as of the date of this Agreement. Except as otherwise indicated in that Schedule, all shares of each Subsidiary owned by the Borrower or by any such other Subsidiary are validly issued and fully paid and nonassessable.

Section 4.5 Financial Condition.

The Borrower has furnished to the Lenders its audited consolidated financial statement as of December 31, 2010, and its unaudited interim financial statement as of March 31, 2011. Those financial statements fairly present the financial condition of the Borrower and its Subsidiaries on the dates thereof and the results of their operations and cash flows for the periods then ended, and were prepared in accordance with GAAP, except as expressly noted therein.

Section 4.6 Adverse Change.

There has been no material adverse change in the business, properties or condition (financial or otherwise) of the Borrower since December 31, 2010.

Section 4.7 Litigation.

Except as set forth in the Borrower's Annual Report on Form 10-K for the year ended December 31, 2010, or in any document subsequently filed pursuant to Section 13, 14 or 15(d) of the Exchange Act, there are no actions, suits or proceedings pending or, to the knowledge of the Borrower, threatened against or affecting the Borrower or the properties of the Borrower, before any court or governmental department, commission, board, bureau, agency or instrumentality, domestic or foreign, which, if determined adversely to the Borrower, would have a Material Adverse Effect.

Section 4.8 Environmental Matters.

The Borrower conducts in the ordinary course of business a review of the effect of existing Environmental Laws and existing Environmental Claims on its business, operations and properties and, as a result thereof, the Borrower has reasonably concluded that such Environmental Laws and Environmental Claims could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect, exclusive of Environmental Claims as set forth in the Borrower's Annual Report on Form 10-K for the year ended December 31, 2010, or in any document subsequently filed pursuant to Section 13, 14 or 15(d) of the Exchange Act.

Section 4.9 Margin Regulations.

The Borrower is not engaged in the business of extending credit for the purpose of purchasing or carrying margin stock (within the meaning of Regulation U of the Board of Governors of the Federal Reserve System). No part of the proceeds of any Credit Extension will be used directly or indirectly for any purpose that violates, or that would require any Lender to make any filings in accordance with, the provisions of Regulation T, U or X of the Board of Governors of the Federal Reserve System as now and from time to time hereafter in effect.

Section 4.10 Taxes.

The Borrower has filed all federal and other tax returns and reports required to be filed, and has paid all federal and other taxes, assessments, fees and other governmental charges levied or imposed upon it or its properties, income or assets otherwise due and payable, except those which are being contested in good faith by appropriate proceedings and for which adequate reserves have been provided in accordance with GAAP and except those the failure to file or pay which would not have a Material Adverse Effect. There is no proposed tax assessment against the Borrower that would, if made, have a Material Adverse Effect.

Section 4.11 Titles and Liens.

To the Borrower's knowledge, without having undertaken any search of real property records for this purpose, the Borrower has good and sufficient title to, or valid leasehold interests in, all real property necessary or used in the ordinary conduct of its business, and good title to all other property and assets reflected in the Borrower's most recent consolidated financial statements provided to the Lenders as owned by the Borrower, except for such defects in title as could not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect and other than any sold, as permitted by Section 6.4. As of the date of this Agreement, the property of the Borrower is subject to no Liens other than a permitted pursuant to Section 6.1.

Section 4.12 Intellectual Property.

The Borrower owns or is licensed or otherwise has the right to use all of the patents, trademarks, service marks, trade names, copyrights, contractual franchises, authorizations and other rights that are reasonably necessary for the operation of its business, without conflict with the rights of any other Person, except to the extent that noncompliance would not have a Material Adverse Effect. To the knowledge of the Borrower, no slogan or other advertising device, product, process, method, substance, part or other material now employed, or now contemplated to be employed, by the Borrower infringes upon any rights held by any other Person, except to the extent that noncompliance would not have a Material Adverse Effect. No claim or litigation regarding any of the foregoing is pending or threatened, and no patent, invention, device, application, principle or any statute, law, rule, regulation, standard or code is pending or, to the knowledge of the Borrower, proposed, which, in either case, could reasonably be expected to have a Material Adverse Effect.

Section 4.13 ERISA.

Each of the Borrower and its ERISA Affiliates is in compliance in all material respects with the applicable provisions of ERISA and the Code and published interpretations thereunder, except for any such failure that, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Effect. No ERISA Event has occurred or is reasonably expected to occur that, when taken together with all other such ERISA Events for which liability is reasonably expected to occur, could reasonably be expected to result in a Material Adverse Effect.

ARTICLE V
Affirmative Covenants

So long as any Note shall remain unpaid or the Facility shall be outstanding, the Borrower will comply with the following requirements, unless the Required Lenders shall otherwise consent in writing:

Section 5.1 Reporting.

The Borrower will deliver to each Lender:

(a) As soon as available, and in any event within 90 days after the end of each fiscal year of the Borrower, a copy of the annual audit report of the Borrower and its Subsidiaries prepared on a consolidated basis with an unqualified opinion of independent certified public accountants selected by the Borrower and acceptable to the Required Lenders, which annual report shall include the consolidated balance sheets of the Borrower and its Subsidiaries as of the end of such fiscal year and the related consolidated statements of income, common stockholders' equity and cash flows of the Borrower and its Subsidiaries for the fiscal year then ended, all in reasonable detail and all prepared in accordance with GAAP.

(b) As soon as available, and in any event within 120 days after the end of each fiscal year of the Borrower:

(i) A copy of the unaudited nonconsolidated balance sheets of the Borrower at the end of such fiscal year and the related unaudited nonconsolidated statements of income, retained earnings and cash flows of the Borrower for such fiscal year, in reasonable detail, all prepared in accordance with GAAP.

(ii) A copy of the annual audit report-regulatory basis of the Borrower with an unqualified opinion of independent certified public accountants selected by the Borrower and acceptable to the Required Lenders, which annual report shall include a copy of the balance sheet-regulatory basis of the Borrower as the end of such fiscal year and the related statements of income-regulatory basis, retained earnings-regulatory basis and cash flows-regulatory basis of the Borrower for the fiscal year then ended, all prepared in accordance with FERC Accounting Principles.

(c) As soon as available and in any event within 45 days after the end of each fiscal quarter of the Borrower, a copy of (A) the unaudited consolidated balance sheets of the Borrower and its Subsidiaries as of the end of such quarter, (B) the related unaudited consolidated statements of income for such quarter, and (C) the related unaudited consolidated statements of income and cash flows of the Borrower and its Subsidiaries for the year to date, all in reasonable detail and prepared in accordance with GAAP, subject to year-end audit adjustments.

(d) As soon as available and in any event within 60 days after the end of each fiscal quarter of the Borrower, a copy of (A) the unaudited nonconsolidated balance sheets of the Borrower at the end of such quarter, (B) the related unaudited nonconsolidated statements of income for such quarter, and (C) the related unaudited nonconsolidated statements of income, retained earnings and cash flows of the Borrower for the year to date, all in reasonable detail and prepared in accordance with GAAP, subject to year-end adjustments.

(e) Concurrently with the delivery of any financial statements under paragraph (a), (b), (c) or (d), a Compliance Certificate, duly executed by the chief financial officer of the Borrower.

(f) Promptly following the issuance thereof, a copy of any Authorizing Order not previously delivered to the Administrative Agent.

(g) Promptly upon their distribution, copies of all financial statements, reports and proxy statements which the Borrower shall have sent to its stockholders.

(h) Promptly after the sending or filing thereof, copies of all regular and periodic financial reports which the Borrower shall file with the Securities and Exchange Commission or any national securities exchange.

(i) Promptly upon becoming available, copies of any reports or applications filed by the Borrower with any governmental body if such reports indicate any material change in the business, operations, affairs or condition of the Borrower, or if copies thereof are requested by any Lender.

(j) Immediately after the commencement thereof, notice in writing of all litigation and of all proceedings before any governmental or regulatory agency affecting the Borrower of the type described in Section 4.7 or which seek a monetary recovery against the Borrower in excess of $10,000,000.

(k) As promptly as practicable (but in any event not later than 5 Business Days) after an officer of the Borrower obtains knowledge of the occurrence of any Default or Event of Default, notice of such occurrence, together with a detailed statement by a responsible officer of the Borrower of the steps being taken by the Borrower to cure the effect of such event.

(l) Promptly upon becoming aware of an ERISA Event, a written notice specifying the nature thereof, what action the Borrower has taken, is taking or proposes to take with respect thereto, and, when known, any action taken or threatened by the Internal Revenue Service, the PBGC or the Department of Labor with respect thereto.

(m) Promptly upon (i) the adoption of any Pension Plan, or (ii) the adoption of any amendment to a Pension Plan, if such amendment results in a material increase in contributions or Unfunded Pension Liability, written notice specifying the nature thereof.

(n) Upon request of any Lender, copies of the most recent annual report (Form 5500 Series), including any supporting schedules, filed by the Borrower or any ERISA Affiliate with the Internal Revenue Service with respect to any Plan.

(o) Such information (in addition to that specified elsewhere in this Section) respecting the financial condition and results of operations of the Borrower as any Lender may from time to time reasonably request.

Section 5.2 Books and Records; Inspection and Examination.

The Borrower will keep accurate books of record and account for itself in which true and complete entries will be made in accordance with GAAP and, upon request of any Lender, will give any representative of that Lender access to, and permit such representative to examine, copy or make extracts from, any and all books, records and documents in its possession, to inspect any of its properties and to discuss its affairs, finances and accounts with any of its principal officers, all at such times during normal business hours and as often as any Lender may reasonably request.

Section 5.3 Compliance with Laws.

The Borrower will comply with the requirements of applicable laws and regulations, except any law and regulation (i) the compliance with which is contested in good faith or the subject of a bona fide dispute, and (ii) the noncompliance with which would not have a Material Adverse Effect. In addition, and without limiting the foregoing sentence, the Borrower shall (i) ensure, and cause each Subsidiary to ensure, that no Person who owns a controlling interest in or otherwise controls the Borrower or any Subsidiary is or shall be listed on the Specially Designated Nationals and Blocked Person List or other similar lists maintained by the Office of Foreign Assets Control (**"OFAC"**), the Department of the Treasury or included in any Executive Orders, (ii) not use or permit the use of any Credit Extension to violate any of the foreign asset control regulations of OFAC or any enabling statute or Executive Order relating thereto, and (iii) comply, and cause each Subsidiary to comply, with all applicable Bank Secrecy Act laws and regulations, as amended, and with the Uniting And Strengthening America By Providing Appropriate Tools Required To Intercept And Obstruct Terrorism Act (USA Patriot Act of 2001).

Section 5.4 Payment of Taxes and Other Claims.

The Borrower will pay or discharge, when due, (a) all taxes, assessments and governmental charges levied or imposed upon it or upon its income or profits, or upon any properties belonging to it, prior to the date on which penalties attach thereto, (b) all federal, state and local taxes required to be withheld by it, and (c) all lawful claims for labor, materials and supplies which, if unpaid, might by law become a Lien or charge upon any properties of the Borrower; provided, that the Borrower shall not be required to pay any such tax, assessment, charge or claim so long as (x) the amount, applicability or validity of such tax, assessment, charge or claim is being contested in good faith by appropriate proceedings or is the subject of a bona fide dispute, and (y) the Borrower has provided adequate reserves therefor in accordance with GAAP, except (with respect to any of the foregoing) to the extent that the failure to do so could not reasonably be expected to have a Material Adverse Effect.

Section 5.5 Maintenance of Properties.

Subject to transactions permitted by Sections 6.4, the Borrower shall maintain and preserve all its property which is used or useful in its business in good working order and condition, ordinary wear and tear excepted, except to the extent that noncompliance would not have a Material Adverse Effect.

Section 5.6 Insurance.

The Borrower shall maintain with financially sound and reputable independent insurers, insurance with respect to its properties and business against loss or damage of the kinds customarily insured against by Persons engaged in the same or similar business, of such types and in such amounts (including deductibles, co-insurance and self-insurance, if adequate reserves are maintained with respect thereto) as are customarily carried under similar circumstances by such other Persons, except to the extent that noncompliance would not have a Material Adverse Effect, and the Borrower will furnish any Lender upon request full information as to the insurance carried within 15 Business Days.

Section 5.7 Preservation of Corporate Existence.

Subject to transactions permitted by Section 6.4, the Borrower shall (iv) preserve and maintain in full force and effect its corporate existence and good standing under the laws of its state or jurisdiction of incorporation; (v) preserve and maintain in full force and effect all governmental rights, privileges, qualifications, permits, licenses and franchises necessary or desirable in the normal conduct of its business; and (vi) preserve its business organization and goodwill; and (vii) preserve or renew all of its registered patents, trademarks, trade names and service marks; except, in each case, to the extent that failure to do so does not have a Material Adverse Effect.

ARTICLE VI
Negative Covenants

So long as any Note shall remain unpaid or the Facility shall be outstanding, the Borrower agrees that, without the prior written consent of the Required Lenders:

Section 6.1 Liens.

The Borrower will not create, incur or suffer to exist any Lien in, of or on the property of the Borrower, except:

(a) Liens for taxes, assessments of governmental charges or levies on its property if the same shall not at the time be delinquent or thereafter can be paid without penalty, or are being contested in good faith and by appropriate proceedings.

(b) Liens imposed by law, such as carriers', warehousemen's and mechanics' liens and other similar liens arising in the ordinary course of business which secure payment of obligations not yet due and payable or remaining payable without penalty or which are being contested in good faith by appropriate proceedings.

(c) Liens arising out of pledges or deposits under worker's compensation laws, unemployment insurance, old age pensions, or other social security or retirement benefits, or similar legislation.

(d) Utility easements, buildings restrictions and such other encumbrances or charges against real property as are of a nature generally existing with respect to properties of a similar character and which do not in any material way affect the marketability of the same or interference with the use thereof in the business of the Borrower.

(e) Purchase money Liens upon or in any property acquired or held by the Borrower in the ordinary course of business, provided that (i) no such Lien is created later than the 90th day following the acquisition or completion of construction of such property by the Borrower, and (ii) no such Lien extends or shall extend to or cover any property of the Borrower other than the property then being acquired, fixed improvements then or thereafter erected thereon and improvements and modifications thereto necessary to maintain such properties in working order.

(f) Liens incurred or deposits made in the ordinary course of business to secure (or to obtain letters of credit that secure) the performance of tenders, statutory obligations, surety bonds, appeal bonds, bids, leases (other than Capitalized Leases), performance bonds, purchase, construction or sales contracts and other similar obligations, in each case not incurred or made in connection with the incurrence of any Obligation.

(g) Liens resulting from judgments, unless such judgments are not bonded or otherwise discharged within 60 days; are not stayed pending appeal or otherwise being appropriately contested in good faith; or are not discharged within 45 days after expiration of any such stay.

(h) Liens created under or in connection with the Indenture as such Indenture exists on the date hereof, without regard to any waiver, amendment, modification or restatement thereof.

(i) Liens permitted under the Indenture as such Indenture exists on the date hereof, without regard to any waiver, amendment, modification or restatement thereof.

(j) Liens on any property of the Borrower (other than those described in subsection (e)) securing any indebtedness for borrowed money in existence on the date hereof and listed in Schedule 6.1 hereto.

Section 6.2 Investments.

The Borrower will not purchase or hold beneficially any stock or other securities or evidence of indebtedness of, make or permit to exist any loans or advances to, or make any investment or acquire any interest whatsoever in, any other Person, except:

(a) Investments in cash equivalents and short-term marketable securities pursuant to and in accordance with the terms of the Borrower's then-current investment policy duly adopted by the Board of Directors of the Borrower.

(b) Investments in the MDU Resources Group, Inc. Benefits Protection Trust in accordance with the Borrower's historical practices.

(c) Any existing investment by the Borrower in the voting stock, membership interests or other equity interests of any Subsidiary.

(d) Any investment by the Borrower in any Subsidiary after the date hereof, so long as (i) the entire amount of such investment is obtained from (A) the issuance of equity interests by the Borrower and/or (B) dividends or similar distributions paid to the Borrower by any other Subsidiary of the Borrower, in each case concurrent with the Borrower's investment in such Subsidiary, and (ii) no Default or Event of Default has occurred and is continuing when such investment is actually made. In the case of any investment funded as described in clause (i)(B), the applicable dividend or distribution and the corresponding investment shall be accurately and completely reflected on the books and records of the Borrower and the applicable Subsidiaries.

(e) Consolidations, mergers and acquisitions not prohibited by Section 6.6.

(f) Travel, relocation and similar advances made to officers and employees of the Borrower in anticipation of expenses to be incurred by such officers and employees, in each case in the ordinary course of the Borrower's business consistent with the Borrower's past practices.

(g) Advances in the form of progress payments, prepaid rent or security deposits.

(h) Evidences of indebtedness in the nature of accounts receivable or notes receivable arising from the sale or lease of goods or services in the ordinary course of business.

(i) Investments made for the purpose of economic development, so long as the aggregate value of the investments permitted by this clause (i) does not exceed $10,000,000.

Section 6.3 Distributions.

The Borrower will not make any Distribution at any time following and during the continuance of any Default or Event of Default arising under paragraph (a), (b), (g) or (h) of Section 7.1.

Section 6.4 Sale of Assets.

The Borrower will not lease, sell or otherwise dispose of all, or a substantial portion of, its property, assets or business (whether in one transaction or in a series of transactions) to any other Person except for sales of inventory in the ordinary course of business. For purposes of this Section, **"substantial portion"** means assets (including other Persons) (i) representing more than 20% of the consolidated assets of the Borrower as reflected in the most recent consolidating financial statement of the Borrower referred to in Section 4.5, or (ii) responsible for more than 15% of the consolidated net sales or the consolidated net income of the Borrower as reflected in the financial statement referred to in clause (i) above.

Section 6.5 Transactions with Affiliates.

The Borrower shall not enter into any material transaction or arrangement or series of related transactions or arrangements that in the aggregate would be material with any Affiliate of the Borrower, except (i) transactions upon terms no less favorable to the Borrower than would obtain, taking into account all facts and circumstances, in a comparable arm's-length transaction with a Person not an Affiliate of the Borrower, (ii) investments in Subsidiaries to the extent not prohibited by Section 6.2, (iii) Distributions to the extent not prohibited by Section 6.3, and (iv) payments required by regulatory rule or order; in the case of clauses (i), (ii) and (iii), to the extent that such payments are (x) made in the ordinary course of the Borrower's business, (y) consistent with the Borrower's past practices, and (z) fair and reasonable.

Section 6.6 Consolidation and Merger.

The Borrower will not consolidate with or merge into any Person, or permit any other Person to merge into it, or acquire (in a transaction analogous in purpose or effect to a consolidation or merger) all or substantially all of the assets of any other Person or any existing business (whether existing as a separate entity, subsidiary, division, unit, line of business or otherwise) of any Person; provided, however, that the restrictions contained in this Section shall not apply to or prevent the consolidation or merger of any Person with, or a conveyance or transfer of its assets to, the Borrower so long as (i) no Default or Event of Default exists at the time of, or will be caused by, such consolidation, merger, conveyance or transfer, (ii) the Borrower shall be the continuing or surviving corporation, and (iii) the prior, effective written consent or approval of the board of directors or equivalent governing body of the other party to such consolidation, merger, conveyance or transfer is obtained.

Section 6.7 Environmental Laws.

The Borrower will not cause or permit the conduct of its operations or the maintenance of any of its property to violate any Environmental Law, except to the extent that noncompliance would not have a Material Adverse Effect.

Section 6.8 Restrictions on Nature of Business.

The Borrower will not engage in any material line of business that is significantly different from that presently engaged in by the Borrower.

Section 6.9 Consolidated Total Leverage Ratio.

The Borrower will not at any time permit its Consolidated Total Leverage Ratio, determined as of any Covenant Compliance Date, to be greater than 0.65 to 1.

Section 6.10 Borrower Leverage Ratio.

The Borrower will not at any time permit the Borrower Leverage Ratio, determined as of any Covenant Compliance Date, to be greater than 0.65 to 1.

ARTICLE VII
Events of Default, Rights and Remedies

Section 7.1 Events of Default.

"Event of Default", wherever used herein, means any one of the following events:

(a) Default in the payment of any principal of any Note when it becomes due and payable.

(b) Default in the payment of any interest on any Note when the same becomes due and payable and the continuance of such default for a period of two calendar days; or default in the payment of any fees required under Section 2.10 when the same become due and payable and the continuance of such default for a period of five calendar days.

(c) Default in the performance, or breach, of any covenant or agreement on the part of the Borrower contained in Article VI.

(d) Default in the performance, or breach, of any covenant or agreement of the Borrower in this Agreement (other than a covenant or agreement a default in whose performance

or whose breach is elsewhere in this Section specifically dealt with), and the continuance of such default or breach for a period of 30 days after the Lenders have given notice to the Borrower specifying such default or breach and requiring it to be remedied.

(e) Any representation or warranty made by the Borrower in this Agreement or by the Borrower (or any of its officers) in any certificate, instrument, or statement contemplated by or made or delivered pursuant to or in connection with this Agreement, shall prove to have been incorrect or misleading in any material respect when made.

(f) A default under the Indenture or with respect to any other Funded Debt (other than any default dealt with elsewhere in this Section) and the expiration of the applicable period of grace, if any, specified in the applicable evidence of indebtedness, indenture or other instrument; provided, however, that no Event of Default shall be deemed to have occurred under this paragraph if the aggregate amount owing as to all such indebtedness as to which such defaults have occurred and are continuing is less than $15,000,000; provided further that if such default shall be cured by the Borrower, or waived by the holders of such indebtedness, in each case prior to the commencement of any action under Section 7.2 and as may be permitted by such evidence of indebtedness, indenture or other instrument, then the Event of Default hereunder by reason of such default shall be deemed likewise to have been thereupon cured or waived.

(g) The Borrower (i) ceases or fails to be Solvent, or generally fails to pay, or admits in writing its inability to pay, its debts as they become due, subject to applicable grace periods, if any, whether at stated maturity or otherwise; (ii) voluntarily ceases to conduct its business in the ordinary course; (iii) commences any proceeding under any Debtor Relief Law with respect to itself; or (iv) takes any action to effectuate or authorize any of the foregoing.

(h) (i) Any involuntary proceeding under any Debtor Relief Law is commenced or filed against the Borrower, or any writ, judgment, warrant of attachment, execution or similar process is issued or levied against a substantial part of the Borrower’s properties, and any such proceeding or petition shall not be dismissed, or such writ, judgment, warrant of attachment, execution or similar process shall not be released, vacated or fully bonded within 60 days after commencement, filing or levy; or (ii) the Borrower admits the material allegations of a petition against it in any proceeding under any Debtor Relief Law, or an order for relief (or similar order under non-U.S. law) is ordered in any proceeding under any Debtor Relief Law; or (iii) the Borrower acquiesces in the appointment of a receiver, trustee, custodian, conservator, liquidator, mortgagee in possession (or agent therefor), or similar Person for itself or a substantial portion of its property or business.

(i) A Change of Control shall occur with respect to the Borrower.

(j) The Borrower shall fail within 60 days to pay, bond or otherwise discharge any judgment or order for the payment of money in excess of $25,000,000, which is not stayed on appeal or otherwise being appropriately contested in good faith.

(k) (i) The occurrence of an ERISA Event or ERISA Termination Event that, in the opinion of the Required Lenders, when taken together with all other ERISA Events and ERISA Termination Events that shall have occurred, could reasonably be expected to result in a Material Adverse Effect; (ii) the commencement or increase of contributions to, or the adoption of or the amendment of, a Pension Plan by the Borrower or an ERISA Affiliate which has resulted or could reasonably be expected to result in a Material Adverse Effect; or (iii) the Borrower’s or an ERISA Affiliate’s failure to pay when due, after the expiration of any applicable grace period, any installment payment with respect to its withdrawal liability under Section 4201 of ERISA under a

Multiemployer Plan which has resulted or could reasonably be expected to result in a Material Adverse Effect.

(l) Any governmental authority or other administrative or legal authority having regulatory jurisdiction over the Borrower takes any action which has a Material Adverse Effect on the Borrower.

Section 7.2 Rights and Remedies.

Upon the occurrence of an Event of Default or at any time thereafter until such Event of Default is cured to the written satisfaction of the Required Lenders, the Administrative Agent may, with the consent of the Required Lenders, and shall, at the request of the Required Lenders, exercise any or all of the following rights and remedies:

(a) The Administrative Agent may, by notice to the Borrower, declare the Facility to be terminated, whereupon the same shall forthwith terminate.

(b) The Administrative Agent may, by notice to the Borrower, declare the entire unpaid principal amount of the Notes then outstanding, all interest accrued and unpaid thereon, and all other amounts payable under this Agreement to be forthwith due and payable, whereupon the Notes, all such accrued interest and all such amounts shall become and be forthwith due and payable, without presentment, demand, protest or further notice of any kind, all of which are hereby expressly waived by the Borrower.

(c) The Lenders may exercise any other rights and remedies available to them by law or agreement.

Notwithstanding the foregoing, upon the occurrence of an Event of Default described in Section 7.1(g) or 7.1(h) hereof, the entire unpaid principal amount of the Notes then outstanding, all interest accrued and unpaid thereon, and all other amounts payable under this Agreement shall be immediately due and payable without presentment, demand, protest or notice of any kind.

Section 7.3 Right of Setoff.

If an Event of Default shall have occurred and shall be continuing, each Lender Party and each of their Affiliates is hereby authorized at any time and from time to time, to the fullest extent permitted by applicable law, to set off and apply any and all deposits (general or special, time or demand, provisional or final, in whatever currency) at any time held and other obligations (in whatever currency) at any time owing by such Lender Party or any such Affiliate to or for the credit or the account of the Borrower against any and all of the obligations of the Borrower now or hereafter existing under this Agreement or any other Loan Document to such Lender Party or any such Affiliate, irrespective of whether or not such Lender Party shall have made any demand under this Agreement or any other Loan Document and although such obligations of the Borrower may be contingent or unmatured or are owed to a branch or office of such Lender Party different from the branch or office holding such deposit or obligated on such indebtedness. The rights of each Lender Party and its Affiliates under this Section are in addition to other rights and remedies (including other rights of setoff) that such Lender Party or its Affiliates may have.

Section 7.4 Crediting of Payments and Proceeds.

If all or any portion of the Obligations have been accelerated or the Administrative Agent has exercised any remedy set forth in this Agreement or any other Loan Document, all payments received by the Lenders upon the Obligations and all net proceeds from the enforcement of the Obligations shall be applied in the following order:

(a) first, to payment of that portion of the Obligations constituting fees, indemnities, expenses and other amounts, including attorney fees, payable to the Administrative Agent in its capacity as such;

(b) second, to payment of that portion of the Obligations constituting fees, indemnities and other amounts (other than principal and interest) payable to the Lenders under the Loan Documents, including attorney fees (ratably among the Lenders in proportion to the respective amounts described in this clause payable to them);

(c) third, to payment of that portion of the Obligations constituting accrued and unpaid interest on the Loans (ratably among the Lender Parties in proportion to the respective amounts described in this clause payable to them);

(d) fourth, to payment of that portion of the Obligations constituting unpaid principal of the Advances and Hedging Obligations owed to a Lender Hedge Counterparty (ratably among the Lender Parties and Lender Hedge Counterparties in proportion to the respective amounts described in this clause held by them);

(e) fifth, to the remaining Obligations (ratably among the Lender Parties in proportion to the respective amounts described in this clause held by them); and

(f) last, the balance, if any, after all of the Obligations have been indefeasibly paid in full, to the Borrower or as otherwise required by applicable law.

ARTICLE VIII
THE ADMINISTRATIVE AGENT

Section 8.1 Appointment and Authority.

Each of the Lenders hereby irrevocably appoints Wells Fargo to act on its behalf as the Administrative Agent hereunder and under the other Loan Documents and authorizes the Administrative Agent to take such actions on its behalf and to exercise such powers as are delegated to the Administrative Agent by the terms hereof or thereof, together with such actions and powers as are reasonably incidental thereto. The provisions of this Article are solely for the benefit of the Administrative Agent and the Lenders, and the Borrower shall have no rights (as a third party beneficiary or otherwise) of any of such provisions. The use of the term “agent” herein or in any other Loan Documents (or any other similar term) with reference to the Administrative Agent is not intended to connote any fiduciary or other implied (or express) obligations arising under agency doctrine of any applicable law. Instead such term is used as a matter of market custom, and is intended to create or reflect only an administrative relationship between contracting parties.

Section 8.2 Rights as a Lender.

The Person serving as the Administrative Agent hereunder shall have the same rights and powers in its capacity as a Lender as any other Lender and may exercise the same as though it were not the Administrative Agent. The term “Lender” or “Lenders” shall, unless otherwise expressly indicated or unless the context otherwise requires, include the Person serving as the Administrative Agent hereunder in its individual capacity. Such Person and its Affiliates may accept deposits from, lend money to, own securities of, act as the financial advisor or in any other advisory capacity for and generally engage in any kind of business with the Borrower or any Subsidiary or other Affiliate thereof as if such Person were not the Administrative Agent hereunder and without any duty to account therefor to the Lenders.

Section 8.3 Exculpatory Provisions.

(a) The Administrative Agent shall not have any duties or obligations except those expressly set forth herein and in the other Loan Documents, and its duties hereunder shall be administrative in nature. Without limiting the generality of the foregoing, the Administrative Agent:

(i) shall not be subject to any fiduciary or other implied duties, regardless of whether a Default or Event of Default has occurred and is continuing;

(ii) shall not have any duty to take any discretionary action or exercise any discretionary powers, except discretionary rights and powers expressly contemplated hereby or by the other Loan Documents that the Administrative Agent is required to exercise as directed in writing by the Required Lenders (or such other number or percentage of the Lenders as shall be expressly provided for herein or in the other Loan Documents), provided that the Administrative Agent shall not be required to take any action that, in its opinion or the opinion of its counsel, may expose the Administrative Agent to liability or that is contrary to any Loan Document or applicable law, including any action that may be in violation of the automatic stay under any Debtor Relief Law or that may effect a forfeiture, modification or termination of property of a Defaulting Lender in violation of any Debtor Relief Law; and

(iii) shall not, except as expressly set forth herein and in the other Loan Documents, have any duty to disclose, and shall not be liable for the failure to disclose, any information relating to the Borrower or any of its Affiliates that is communicated to or obtained by the Person serving as the Administrative Agent or any of its Affiliates in any capacity.

(b) The Administrative Agent shall not be liable for any action taken or not taken by it (i) with the consent or at the request of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, or as the Administrative Agent shall believe in good faith shall be necessary, under the circumstances as provided in Sections 9.2 and 7.2) or (ii) in the absence of its own gross negligence or willful misconduct as determined by a court of competent jurisdiction by final and nonappealable judgment. The Administrative Agent shall be deemed not to have knowledge of any Default or Event of Default unless and until notice describing such Default or Event of Default is given to the Administrative Agent by the Borrower or a Lender.

(c) The Administrative Agent shall not be responsible for or have any duty to ascertain or inquire into (i) any statement, warranty or representation made in or in connection with this Agreement or any other Loan Document, (ii) the contents of any certificate, report or other document delivered hereunder or thereunder or in connection herewith or therewith, (iii) the performance or observance of any of the covenants, agreements or other terms or conditions set forth herein or therein or the occurrence of any Default or Event of Default, (iv) the validity, enforceability, effectiveness or genuineness of this Agreement, any other Loan Document or any other agreement, instrument or document, or (v) the satisfaction of any condition set forth in Article III or elsewhere herein, other than to confirm receipt of items expressly required to be delivered to the Administrative Agent.

Section 8.4 Reliance by Administrative Agent.

The Administrative Agent shall be entitled to rely upon, and shall not incur any liability for relying upon, any notice, request, certificate, consent, statement, instrument, document or other writing (including any electronic message, Internet or intranet website posting or other distribution) believed by it to be genuine and to have been signed, sent or otherwise authenticated by the proper Person. The Administrative Agent also may rely upon any statement made to it orally or by telephone and believed by it to have been made by the proper Person, and shall not incur any liability for relying thereon. In determining compliance with any condition hereunder to the making of a Loan that by its terms must be fulfilled to the satisfaction of a Lender, the Administrative Agent may presume that such condition is satisfactory to such Lender unless the Administrative Agent shall have received notice to the contrary from such Lender prior to the making of such Loan. The Administrative Agent may consult with legal counsel (who may be counsel for the Borrower), independent accountants and other experts selected by it, and shall not be liable for any action taken or not taken by it in accordance with the advice of any such counsel, accountants or experts.

Section 8.5 Delegation of Duties.

The Administrative Agent may perform any and all of its duties and exercise its rights and powers hereunder or under any other Loan Document by or through any one or more sub-agents appointed by the Administrative Agent. The Administrative Agent and any such sub-agent may perform any and all of its duties and exercise its rights and powers by or through their respective Related Parties. The exculpatory provisions of this Article shall apply to any such sub-agent and to the Related Parties of the Administrative Agent and any such sub-agent, and shall apply to their activities in connection with the syndication of the credit facilities provided for herein as well as activities as Administrative Agent. The Administrative Agent shall not be responsible for the negligence or misconduct of any sub-agents except to the extent that a court of competent jurisdiction determines in a final and non appealable judgment that the Administrative Agent acted with gross negligence or willful misconduct in the selection of such sub-agents.

Section 8.6 Resignation and Removal of Administrative Agent.

(a) The Administrative Agent may at any time give notice of its resignation to the Lenders and the Borrower. Upon receipt of any such notice of resignation, the Required Lenders shall have the right, in consultation with the Borrower, to appoint a successor, which shall be a bank with an office in the United States, or an Affiliate of any such bank with an office in the United States. If no such successor has been so appointed by the Required Lenders and has accepted such appointment within 45 days after the retiring Administrative Agent gives notice of its resignation (or such earlier day as shall be agreed by the Required Lenders) (the **"Resignation Effective Date"**), then the retiring Administrative Agent may (but shall not be obligated to) on behalf of the Lenders appoint a successor Administrative Agent meeting the qualifications set forth above. Whether or not a successor has been appointed, such resignation shall become effective in accordance with such notice on the Resignation Effective Date.

(b) If the Person serving as Administrative Agent is a Defaulting Lender pursuant to clause (d) of the definition thereof, the Required Lenders may, to the extent permitted by applicable law, by notice in writing to the Borrower and such Person remove such Person as Administrative Agent and, in consultation with the Borrower, appoint a successor. If no such successor has been so appointed by the Required Lenders and has accepted such appointment within 30 days (or such earlier day as shall be agreed by the Required Lenders) (the "Removal Effective Date"), then such removal shall nonetheless become effective in accordance with such notice on the Removal Effective Date.

(c) With effect from the Resignation Effective Date or the Removal Effective Date (as applicable), (1) the retiring or removed Administrative Agent shall be discharged from its duties and obligations hereunder and under the other Loan Documents (except that in the case of any collateral security held by the Administrative Agent on behalf of the Lenders under any of the Loan Documents, the retiring or removed Administrative Agent shall continue to hold such collateral security until such time as a successor Administrative Agent is appointed), and (2) all payments, communications and determinations provided to be made by, to or through the Administrative Agent shall instead be made by or to each Lender directly, until such time as the Required Lenders appoint a successor Administrative Agent as provided for above. Upon the acceptance of a successor's appointment as Administrative Agent hereunder, such successor shall succeed to and become vested with all of the rights, powers, privileges and duties of the retiring or removed Administrative Agent, and the retiring or removed Administrative Agent shall be discharged from all of its duties and obligations hereunder or under the other Loan Documents. The fees payable by the Borrower to a successor Administrative Agent shall be the same as those payable to its predecessor unless otherwise agreed between the Borrower and such successor. After the retiring or removed Administrative Agent's resignation or removal hereunder and under the other Loan Documents, the provisions of this Article and Section 9.4 shall continue in effect for the benefit of such retiring or removed Administrative Agent, its sub-agents and their Related Parties in respect of any actions taken or omitted to be taken by any of them while the retiring or removed Administrative Agent was acting as Administrative Agent.

Section 8.7 Non-Reliance on Administrative Agent and Other Lenders.

Each Lender acknowledges that it has, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement. Each Lender also acknowledges that it will, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it shall from time to time deem appropriate, continue to make its own decisions in taking or not taking action under or based upon this Agreement, any other Loan Document or any related agreement or any document furnished hereunder or thereunder.

Section 8.8 No Other Duties, Etc.

Anything herein to the contrary notwithstanding, none of the Persons listed on the cover page hereof as "joint lead arranger," "syndication agent" or "joint lead bookrunner" shall have any powers, duties, obligations or responsibilities under this Agreement or any of the other Loan Documents, except in any capacity, as applicable, as the Administrative Agent or a Lender.

Section 8.9 Administrative Agent May File Proofs of Claim.

In case of the pendency of any proceeding under any Debtor Relief Law or any other judicial proceeding relative to the Borrower, the Administrative Agent (irrespective of whether the principal of any Obligation is then due and payable and irrespective of whether the Administrative Agent has made any demand on the Borrower) shall be entitled and empowered (but not obligated), by intervention in such proceeding or otherwise:

(a) to file and prove a claim for the whole amount of the principal and interest owing and unpaid in respect of the Obligations that are owing and unpaid and to file such other documents as may be necessary or advisable in order to have the claims of the Lender Parties (including any claim for the reasonable compensation, expenses, disbursements and advances of the Lender Parties and their respective agents and counsel and all other amounts due the Lender Parties under Sections 2.10 and 9.4) allowed in such judicial proceeding; and

(b) to collect and receive any monies or other property payable or deliverable on any such claims and to distribute the same;

and any custodian, receiver, assignee, trustee, liquidator, sequestrator or other similar official in any such judicial proceeding is hereby authorized by each Lender Party to make such payments to the Administrative Agent and, in the event that the Administrative Agent consents to the making of such payments directly to the Lender Parties, to pay to the Administrative Agent any amount due for the reasonable compensation, expenses, disbursements and advances of the Administrative Agent and its agents and counsel, and any other amounts due the Administrative Agent under Sections 2.10 and 9.4.

Section 8.10 Collateral and Guaranty Matters.

(a) Each Lender Party hereby irrevocably authorizes the Administrative Agent to act as collateral agent of and for such Lender Party for purposes of holding, perfecting and disposing of collateral under the Loan Documents and appoints the Administrative Agent as nominal beneficiary or nominal secured party, as the case may be, under the Loan Documents and all related UCC financing statements. Without limiting the foregoing, the Lenders irrevocably authorize the Administrative Agent, at its option and in its discretion,

(i) to release any Lien on any property granted to or held by the Administrative Agent under any Loan Document (A) upon termination of all Commitments and payment in full of all Obligations (other than contingent indemnification obligations), (B) that is sold or otherwise disposed of or to be sold or otherwise disposed of as part of or in connection with any sale or other disposition permitted under the Loan Documents, or (C) subject to Section 9.2, if approved, authorized or ratified in writing by the Required Lenders;

(ii) to subordinate any Lien on any property granted to or held by the Administrative Agent under any Loan Document to the holder of any Lien on such property that is permitted by Section 6.1(e); and

(iii) to release any guarantor from its obligations under any guaranty of the Obligations if such Person ceases to be a Subsidiary as a result of a transaction permitted under the Loan Documents.

Upon request by the Administrative Agent at any time, the Required Lenders will confirm in writing the Administrative Agent's authority to release or subordinate its interest in particular types or items of property, or to release any guarantor from its obligations pursuant to this Section 8.10.

(b) The Administrative Agent shall not be responsible for or have a duty to ascertain or inquire into any representation or warranty regarding the existence, value or collectability of any collateral, the existence, priority or perfection of the Administrative Agent's Lien thereon, or any certificate prepared by the Borrower in connection therewith, nor shall the Administrative Agent be responsible or liable to any Lender Party for any failure to monitor or maintain any portion of the collateral.

ARTICLE IX
Miscellaneous

Section 9.1 No Waiver; Cumulative Remedies.

No failure or delay on the part of any Lender Party in exercising any right, power or remedy under the Loan Documents shall operate as a waiver thereof; nor shall any acceptance of payments while any Default or Event of Default is outstanding operate as a waiver of such Default or Event of Default, or any right, power or remedy under the Loan Documents; nor shall any single or partial exercise of any such right, power or remedy preclude any other or further exercise thereof or the exercise of any other right, power or remedy under the Loan Documents. The remedies provided in the Loan Documents are cumulative and not exclusive of any remedies provided by law.

Section 9.2 Amendments, Etc.

No amendment or waiver of any provision of any Loan Document or consent to any departure by the Borrower therefrom shall be effective unless the same shall be in writing and signed by the Required Lenders (or by the Administrative Agent with the consent or at the request of the Required Lenders), and, if the rights or duties of the Administrative Agent are affected thereby, by the Administrative Agent. Notwithstanding the foregoing, no amendment, modification, termination, waiver or consent shall do any of the following unless the same shall be in writing and signed by the Administrative Agent and each Lender affected thereby (and, as to clauses (d) and (f) hereof, all Lenders shall be deemed affected): (a) change the amount of any Commitment (except as permitted in accordance with Section 2.13, 2.14 or 9.6(b)), (b) reduce the amount of any principal, interest fees or other amounts payable to a Lender under any Loan Document, (c) postpone any date fixed for, or reduce the amount of, any payment of principal, interest, fees or other amounts payable to a Lender under any Loan Document, (d) change the definition of "Required Lenders," (e) amend Section 7.4 in a manner that would alter the ratable sharing of payments provided thereby, or (f) amend this Section 9.2 or any other provision of this Agreement requiring the consent or other action of the Required Lenders or any particular Lender. Notwithstanding anything to the contrary herein, no Lender who is at the time a Defaulting Lender shall have any right to approve or disapprove any amendment, waiver or consent hereunder, except that (y) the Commitment of such Lender may not be increased or extended without the consent of such Lender, and (z) without the consent of all Defaulting Lenders, no amendment may be effected that has an adverse impact on the Defaulting Lenders (as a class) that is materially different than the impact of such amendment on the Non-Defaulting Lenders. Any waiver shall be effective only in the specific instance and for the specific purpose for which given. No notice to or demand on the Borrower in any case shall entitle the Borrower to any other or further notice or demand in similar or other circumstances.

Section 9.3 Notices; Distribution of Information Via Electronic Means.

(a) *Use of Platform to Distribute Communications*. The Administrative Agent may make any material delivered by the Borrower to the Administrative Agent, as well as any amendments, waivers, consents, and other written information, documents, instruments and other materials relating to the Borrower, or any of its Subsidiaries, or any other materials or matters relating to any Loan Documents, or any of the transactions contemplated hereby or thereby (collectively, the **"Communications"**) available to the Lender Parties by posting such notices on an electronic delivery system such as IntraLinks or a substantially similar electronic system (the **"Platform"**). The Platform is provided "as is" and "as available," and neither the Administrative Agent nor any of its Affiliates warrants the accuracy, completeness, timeliness, sufficiency, or sequencing of the Communications posted on the Platform. The Administrative Agent and its Affiliates expressly disclaim with respect to the Platform any liability for errors in transmission, incorrect or incomplete downloading, delays in posting or delivery, or problems accessing the

Communications posted on the Platform. No warranty of any kind, express, implied or statutory, including any warranty of merchantability, fitness for a particular purpose, non-infringement of third party rights or freedom from viruses or other code defects, is made by the Administrative Agent or any of its Affiliates in connection with the Platform.

(b) *Notice by Electronic Means*. Each Lender agrees (i) on or before the date it becomes a party to this Agreement, to notify the Administrative Agent in writing of the e-mail addresses to which a notice under this Agreement (herein, a **"Notice"**) may be sent to it and from time to time thereafter to ensure that the Administrative Agent has on record an effective e-mail address for it, and (ii) that any Notice may be sent to such e-mail addresses. Each Lender agrees that an e-mail message notice to it (as provided in the previous sentence) specifying that any Communication has been posted to the Platform shall for purposes of this Agreement constitute effective delivery to such Lender of such information, documents or other materials comprising such Communication.

(c) *Notices By Other Means*. Except as otherwise expressly provided herein, all notices, requests, demands and other communications provided for under the Loan Documents shall be in writing (including facsimile transmission or email) and shall be sent to the applicable party at its address, e-mail address or facsimile number set forth on Exhibit A or on any Administrative Questionnaire, or as to each party, at such other address, e-mail address or facsimile number as shall be designated by such party in a written notice to the other party complying as to delivery with the terms of this Section 9.3. All such notices, requests, demands and other communications shall be effective (i) when received, if sent by facsimile, email, hand delivery or overnight courier, or (ii) three Business Days after the date when sent by registered or certified mail, postage prepaid; provided, however, that notices or requests to the Administrative Agent or any Lender pursuant to any of the provisions of Article II shall not be effective until received by the Administrative Agent or such Lender.

Section 9.4 Expenses; Indemnity; Damage Waiver

(a) *Costs and Expenses*. The Borrower shall pay (i) all reasonable out-of-pocket expenses incurred by the Administrative Agent and its Affiliates (including the reasonable fees, charges and disbursements of counsel for the Administrative Agent), in connection with the preparation, negotiation, execution, delivery and administration of this Agreement and the other Loan Documents or any amendments, modifications or waivers of the provisions hereof or thereof (whether or not the transactions contemplated hereby or thereby shall be consummated) and (ii) all out-of-pocket expenses incurred by the Administrative Agent or any Lender (including the fees, charges and disbursements of any counsel for the Administrative Agent or any Lender and specifically including allocated costs of in-house counsel if not duplication of the services of outside counsel) in connection with the enforcement or protection of its rights (A) in connection with this Agreement and the other Loan Documents, including its rights under this Section 9.4, or (B) in connection with the Obligations, including all such out-of-pocket expenses incurred during any workout, restructuring or negotiations in respect of the Obligations.

(b) *Indemnification by the Borrower*. The Borrower shall indemnify each Lender Party and each Affiliate of any Lender Party (each such Person being called an **"Indemnitee"**) against, and hold each Indemnitee harmless from, any and all losses, claims, damages, liabilities and related expenses (including the fees, charges and disbursements of any counsel for any Indemnitee and specifically including allocated costs of in-house counsel if not duplication of the services of outside counsel) incurred by any Indemnitee or asserted against any Indemnitee by any third party or the Borrower arising out of, in connection with, or as a result of (i) the execution or delivery of this Agreement, any other Loan Document or any agreement or instrument contemplated hereby or thereby, the performance by the parties hereto of their respective obligations hereunder or thereunder or the consummation of the transactions contemplated hereby or thereby, (ii) the Loans or the use or proposed use of the proceeds therefrom, (iii) any actual or alleged presence or release of Hazardous Substances on or from any property owned or operated by the Borrower or its Subsidiaries, or any liability arising from any alleged breach of Environmental Laws related in any way to the Borrower or its Subsidiaries, or (iv) any actual or prospective claim, litigation, investigation or proceeding relating to any of the foregoing, whether based on contract, tort or any other theory, whether brought by a third party or by the Borrower, and regardless of whether any Indemnitee is a party thereto, provided that such indemnity shall not, as to any Indemnitee, be available to the extent that such losses, claims, damages, liabilities or related expenses (x) are determined by a court of competent jurisdiction by final and nonappealable judgment to have resulted from the negligence or willful misconduct of such Indemnitee or (y) result from a claim brought by the Borrower against an Indemnitee for breach of such Indemnitee's obligations hereunder or under any other Loan Document, if the Borrower has obtained a final and nonappealable judgment in its favor on such claim as determined by a court of competent jurisdiction.

(c) *Reimbursement by Lenders*. To the extent that the Borrower for any reason fails to indefeasibly pay any amount required under paragraph (a) or (b) of this Section 9.4 to be paid by it to the Administrative Agent (or any sub-agent thereof), or any Affiliate of any of the foregoing, each Lender severally agrees to pay to the Administrative Agent (or any such sub-agent) or such Affiliate, as the case may be, such Lender's Percentage (determined as of the time that the applicable unreimbursed expense or indemnity payment is sought) of such unpaid amount, provided that the unreimbursed expense or indemnified loss, claim, damage, liability or related expense, as the case may be, was incurred by or asserted against the Administrative Agent (or any such sub-agent) in its capacity as such, or against any Affiliate of any of the foregoing acting for the Administrative Agent (or any such sub-agent) in connection with such capacity. The obligations of the Lenders under this paragraph (c) are subject to the provisions of Section 2.23.

(d) *Waiver of Consequential Damages, Etc.* To the fullest extent permitted by applicable law, the Borrower shall not assert, and hereby waives, any claim against any Indemnitee, on any theory of liability, for special, indirect, consequential or punitive damages (as opposed to direct or actual damages) arising out of, in connection with, or as a result of, this Agreement, any other Loan Document or any agreement or instrument contemplated hereby, the transactions contemplated hereby or thereby, the Loans or the use of the proceeds thereof. No Indemnitee referred to in paragraph (b) above shall be liable for any damages arising from the use by unintended recipients of any information or other materials distributed by it through telecommunications, electronic or other information transmission systems in connection with this Agreement or the other Loan Documents or the transactions contemplated hereby or thereby.

(e) *Payments*. All amounts due under this Section 9.4 shall be payable promptly after demand therefor.

(f) *Survival*. The agreements in this Section 9.4 shall survive the resignation of the Administrative Agent, the replacement of any Lender, the termination in full of all of the Commitments and the payment, satisfaction or discharge in full of all the other Obligations.

Section 9.5 Execution in Counterparts.

This Agreement and the other Loan Documents may be executed in any number of counterparts, each of which when so executed and delivered shall be deemed to be an original and all of which counterparts of this Agreement or such other Loan Document, as the case may be, taken together, shall constitute but one and the same instrument.

Section 9.6 Successors and Assigns; Register.

(a) *Successors and Assigns Generally*. The provisions of this Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted hereby, except that the Borrower may not assign or otherwise transfer any of its rights or obligations hereunder without the prior written consent of the Administrative Agent and each Lender, and no Lender may assign or otherwise transfer any of its rights or obligations hereunder, except (i) to an assignee in accordance with the provisions of paragraph (b) of this Section, (ii) by way of participation in accordance with the provisions of paragraph (d) of this Section or (iii) by way of pledge or assignment of a Lien subject to the restrictions of paragraph (f) of this Section (and any other attempted assignment or transfer by any party hereto shall be null and void). Nothing in this Agreement, express or implied, shall be construed to confer upon any Person (other than the parties hereto, their respective successors and assigns permitted hereby, Participants to the extent provided in paragraph (d) of this Section and, to the extent expressly contemplated hereby, the Affiliates of each of the Administrative Agent and the Lenders) any legal or equitable right, remedy or claim under or by reason of this Agreement.

(b) *Assignments by Lenders*. Any Lender may at any time assign to one or more Eligible Assignees all or a portion of its rights and obligations under this Agreement (including all or a portion of its Commitments and the Loans at the time owing to it); provided that any such assignment shall be subject to the following conditions:

(i) *Minimum Amounts*.

(A) In the case of an assignment of the entire remaining amount of the assigning Lender's Commitment and the Loans at the time owing to it or in the case of an assignment to a Lender, no minimum amount need be assigned.

(B) In any case not described in paragraph (b)(i)(A) of this Section, (i) through the Revolving Commitment Termination Date, the aggregate amount of the Commitment (which for this purpose includes Advances outstanding thereunder) of the assigning Lender subject to each such assignment (determined as of the date the Assignment and Assumption with respect to such assignment is delivered to the Administrative Agent or, if **"Trade Date"** is specified in the Assignment and Assumption, as of such Trade Date) shall not be less than 25% of the Aggregate Revolving Commitment Amount then in effect, and (ii) thereafter, the principal outstanding balance of the Advances of the assigning Lender subject to each such assignment (determined as of the date the Assignment and Assumption with respect to such assignment is delivered to the Administrative Agent or, if **"Trade Date"** is specified in the Assignment and Assumption, as of such Trade Date) shall not be less than $5,000,000.

(ii) *Required Consents*. No consent shall be required for any assignment except as follows:

(A) the consent of the Borrower (such consent not to be unreasonably withheld or delayed) shall be required unless (x) a Default or Event of Default has occurred and is continuing at the time of such assignment, or (y) such assignment is to a Lender; provided that the Borrower shall be deemed to have consented to any such assignment unless it shall object thereto by written notice to the Administrative Agent within 5 Business Days after having received notice thereof.

(B) The consent of the Administrative Agent shall be required for assignments in respect of a Facility if such assignment is to a Person that is not a Lender.

(iii) *Assignment and Assumption*. The parties to each assignment shall execute and deliver to the Administrative Agent an Assignment and Assumption, together with a processing and recordation fee of $3,500; provided that the Administrative Agent may, in its sole discretion, elect to waive such processing and recordation fee in the case of any assignment**.** The assignee, if it is not a Lender, shall deliver to the Administrative Agent an Administrative Questionnaire.

(iv) *No Assignment to Certain Persons*. No such assignment shall be made to (A) the Borrower or any of the Borrower's Affiliates or Subsidiaries, or (B) to any Defaulting Lender or any of its Subsidiaries, or any Person who, upon becoming a Lender hereunder, would constitute any of the foregoing Persons described in this clause (B).

(v) *No Assignment to Natural Persons*. No such assignment shall be made to a natural person.

(vi) *Certain Additional Payments*. In connection with any assignment of rights and obligations of any Defaulting Lender hereunder, no such assignment shall be effective unless and until, in addition to the other conditions thereto set forth herein, the parties to the assignment shall make such additional payments to the Administrative Agent in an aggregate amount sufficient, upon distribution thereof as appropriate (which may be outright payment, purchases by the assignee of participations or subparticipations, or other compensating actions, including funding, with the consent of the Borrower and the Administrative Agent, the applicable pro rata share of Loans previously requested but not funded by the Defaulting Lender, to each of which the applicable assignee and assignor hereby irrevocably consent), to (x) pay and satisfy in full all payment liabilities then owed by such Defaulting Lender to the Administrative Agent and each other Lender hereunder (and interest accrued thereon), and (y) acquire (and fund as appropriate) its full pro rata share of all Loans in accordance with its Percentage. Notwithstanding the foregoing, in the event that any assignment of rights and obligations of any Defaulting Lender hereunder shall become effective under applicable law without compliance with the provisions of this paragraph, then the assignee of such interest shall be deemed to be a Defaulting Lender for all purposes of this Agreement until such compliance occurs.

Subject to acceptance and recording thereof by the Administrative Agent pursuant to paragraph (c) of this Section, from and after the effective date specified in each Assignment and Assumption, the assignee thereunder shall be a party to this Agreement and, to the extent of the interest assigned by such Assignment and Assumption, have the rights and obligations of a Lender under this Agreement, and the assigning Lender thereunder shall, to the extent of the interest assigned by such Assignment and Assumption, be released from its obligations under this Agreement (and, in the case of an Assignment and Assumption covering all of the assigning Lender's rights and obligations under this Agreement, such Lender shall cease to be a party hereto) but shall continue to be entitled to the benefits of Sections 2.16, 9.4(a) and 9.4(b) with respect to facts and circumstances occurring prior to the effective date of such assignment; provided, that except to the extent otherwise expressly agreed by the affected parties, no assignment by a Defaulting Lender will constitute a waiver or release of any claim of any party hereunder arising from that Lender's having been a Defaulting Lender. Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this paragraph shall be treated for purposes of this Agreement as a sale by such Lender of a participation in such rights and obligations in accordance with paragraph (d) of this Section.

(c) *Register*. The Borrower hereby designates the Administrative Agent to serve as the Borrower's agent, solely for purposes of this Section 9.6(c), to maintain a register (the **"Register"**) on which it will record the Commitments from time to time of each of the Lenders, the Loans made by each of the Lenders and each repayment in respect of the principal amount of the Loans of each Lender. Failure to make any such recordation, or any error in such recordation, shall not affect the Borrower's obligations in respect of such Loans. With respect to any Lender, the transfer of any Commitment of such Lender and the rights to the principal of, and interest on, any Loan shall not be effective until such transfer is recorded on the Register maintained by the Administrative Agent with respect to ownership of such Commitment and Loans and prior to such recordation all amounts owing to the transferor with respect to such Commitment and Loans shall remain owing to the transferor. The registration of assignment or transfer of all or part of any Commitment or Loan shall be recorded by the Administrative Agent on the Register only upon the acceptance by the Administrative Agent of a properly executed and delivered Assignment and Assumption Agreement pursuant to Section 9.6(b). Coincident with the delivery of such an Assignment and Assumption Agreement to the Administrative Agent for acceptance and registration of assignment or transfer of all or part of a Loan, or as soon thereafter as practicable, the assigning or transferor Lender shall surrender the Note (if any) evidencing such Commitment, and thereupon one or more new Notes in the same aggregate principal amount shall be issued to the assigning or transferor Lender and/or the new Lender at the request of any such Lender. The Borrower agrees to indemnify the Administrative Agent from and against any and all losses, claims, damages and liabilities of whatsoever nature which may be imposed on, asserted against or incurred by the Administrative Agent in performing its duties under this Section 9.6(c).

(d) *Participations*. Any Lender may at any time, without the consent of, or notice to, the Borrower or the Administrative Agent, sell participations to any Person (other than a natural person, the Borrower, or any of the Borrower's Affiliates or Subsidiaries) (each, a **"Participant"**) in all or a portion of such Lender's rights and/or obligations under this Agreement (including all or a portion of its Commitment and/or the Loans owing to it); provided that (i) such Lender's obligations under this Agreement shall remain unchanged, (ii) such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations and (iii) the Borrower, the Administrative Agent and the Lenders shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under this Agreement. Any agreement or instrument pursuant to which a Lender sells such a participation shall provide that such Lender shall retain the sole right to enforce this Agreement and to approve any amendment, modification or waiver of any provision of this Agreement; provided that such agreement or instrument may provide that such Lender will not, without the consent of the Participant, agree to any amendment, modification or waiver that would (i) forgive any indebtedness of the Borrower under this Agreement or the Notes, (ii) agree to reduce the rate of interest charged under this Agreement, or (iii) agree to extend the final maturity of any indebtedness evidenced by the Notes, except as expressly provided by the terms of the Loan Documents, in each case to the extent that such amendment, modification or waiver would affect such Participant. Subject to paragraph (e) of this Section, the Borrower agrees that each Participant shall be entitled to the benefits of Sections 2.16 and 2.17 to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to paragraph (b) of this Section. To the extent permitted by law, each Participant also shall be entitled to the benefits of Section 7.3 as though it were a Lender, provided such Participant agrees to be subject to Section 9.7 as though it were a Lender.

(e) *Limitations upon Participant Rights*. A Participant shall not be entitled to receive any greater payment under Sections 2.16 and 2.17 than the applicable Lender would have been entitled to receive with respect to the participation sold to such Participant, unless the sale of the participation to such Participant is made with the Borrower's prior written consent. A Participant that would be a Foreign Lender if it were a Lender shall not be entitled to the benefits of Section 2.17 unless the Borrower is notified of the participation sold to such Participant and such Participant agrees, for the benefit of the Borrower, to comply with Section 2.17(e) as though it were a Lender.

(f) *Certain Pledges*. Any Lender may at any time pledge or assign a Lien in all or any portion of its rights under this Agreement to secure obligations of such Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank; provided that no such pledge or assignment shall release such Lender from any of its obligations hereunder or substitute any such pledgee or assignee for such Lender as a party hereto.

Section 9.7 Sharing of Payments by Lenders.

If any Lender shall, by exercising any right of setoff or counterclaim or otherwise, obtain payment in respect of any principal of or interest on any of its Loans or other obligations hereunder resulting in such Lender's receiving payment of a proportion of the aggregate amount of its Loans and accrued interest thereon or other such obligations greater than its pro rata share thereof as provided herein, then the Lender receiving such greater proportion shall (a) notify the Administrative Agent of such fact, and (b) purchase (for cash at face value) participations in the Loans and such other obligations of the other Lenders, or make such other adjustments as shall be equitable, so that the benefit of all such payments shall be shared by the Lenders ratably in accordance with the aggregate amount of principal of and accrued interest on their respective Loans and other amounts owing them, provided that:

Section 9.8 Disclosure of Information.

The Administrative Agent and the Lenders shall keep confidential (and cause their respective officers, directors, employees, agents and representatives to keep confidential) all information, materials and documents furnished by the Borrower, the Administrative Agent or the Lenders (the **"Disclosed Information"**). Notwithstanding the foregoing, the Administrative Agent and each Lender may disclose Disclosed Information (i) to the Administrative Agent, any other Lender or any Affiliate of any Lender; (ii) to legal counsel, accountants and other professional advisors to the Administrative Agent or such Lender; (iii) to any regulatory body having jurisdiction over any Lender or the Administrative Agent; (iv) to the extent required by applicable laws and regulations or by any subpoena or similar legal process, or requested by any governmental agency or authority; (v) to the extent such Disclosed Information (A) becomes publicly available other than as a result of a breach of this Agreement, (B) becomes available to the Administrative Agent or such Lender on a non-confidential basis from a source other than the Borrower or a Subsidiary, or (C) was available to the Administrative Agent or such Lender on a non-confidential basis prior to its disclosure to the Administrative Agent or such Lender by the Borrower or a Subsidiary; (vi) to the extent the Borrower or such Subsidiary shall have consented to such disclosure in writing; (vii) to the extent reasonably deemed necessary by the Administrative Agent or any Lender in the enforcement of the remedies of the Administrative Agent and the Lenders provided under the Loan Documents; or (viii) in connection with any potential assignment or participation in the interest granted hereunder, provided that any such potential assignee or participant shall have executed a confidentiality agreement imposing on such potential assignee or participant substantially the same obligations as are imposed on the Administrative Agent and the Lenders under this Section 9.8.

Section 9.9 Governing Law.

The Loan Documents shall be governed by, and construed in accordance with, the laws of the State of New York.

Section 9.10 Consent to Jurisdiction.

Each of the Borrower, the Administrative Agent and the Lenders irrevocably (i) agrees that any suit, action or other legal proceeding arising out of or relating to this Agreement or any other Loan Document shall be brought in a court of record in Hennepin County in the State of Minnesota or in the courts of the United States located in such State, (ii) consents to the jurisdiction of each such court in any suit, action or proceeding, (iii) waives any objection which it may have to the laying of venue of any such suit, action or proceeding in any such courts and any claim that any such suit, action or proceeding has been brought in an inconvenient forum, and (iv) agrees that a final judgment in any such suit, action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law after all appeals have been exhausted.

Section 9.11 Waiver of Jury Trial.

THE BORROWER, THE ADMINISTRATIVE AGENT AND THE LENDERS HEREBY WAIVE TRIAL BY JURY IN ANY JUDICIAL PROCEEDING INVOLVING, DIRECTLY OR INDIRECTLY, ANY MATTER (WHETHER SOUNDING IN TORT, CONTRACT OR OTHERWISE) IN ANY WAY ARISING OUT OF, RELATED TO, OR CONNECTED WITH THIS AGREEMENT AND THE NOTES OR THE RELATIONSHIPS ESTABLISHED HEREUNDER.

Section 9.12 Severability of Provisions.

Any provision of this Agreement which is prohibited or unenforceable shall be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof.

Section 9.13 Prior Agreements.

This Agreement and the other Loan Documents and related documents described herein restate and supersede in their entirety any and all prior agreements and understandings, oral or written, between the Lenders and the Borrower.

Section 9.14 Other Financing.

If at any time from and after the effective date of this Agreement, the Borrower shall enter into any trust indenture, credit agreement or other agreement for, relating to, or amending any terms or conditions applicable to any unsecured indebtedness in an amount not less than $15,000,000, the Borrower shall promptly so advise the Administrative Agent. Thereupon, if the Required Lenders shall determine that such trust indenture, credit agreement or other agreement includes covenants reasonably determined by the Required Lenders to be more restrictive than those set forth in Articles V and VI, or defaults reasonably determined by the Required Lenders to be less favorable to the Borrower than those set forth in Article VII, and shall request by notice to the Borrower, the Borrower shall enter into an amendment to this Agreement providing for substantially the same such covenants and defaults as those provided for in such trust indenture, credit agreement or other agreement, to the extent required and as may be selected by the Required Lenders, such amendment to remain in effect for the entire duration of the term to maturity of such indebtedness (to and including the date to which the same may be extended); provided, however, that if any such trust indenture, credit agreement or other agreement shall be modified, supplemented, amended or terminated so as to modify, amend or eliminate such trust indenture or other agreement or any such covenant, term, condition or default so made a part of this Agreement, then, the Borrower shall give the Administrative Agent and the Lenders prompt notice thereof and such modification, supplement or amendment shall operate to modify, amend or eliminate such covenants, term, condition or default as so made a part of this Agreement. Notwithstanding the foregoing, in no event shall this Section 9.14 be construed so as to require the Borrower at any time to grant any Lien in favor of the Administrative Agent or the Lenders hereunder.

Section 9.15 Termination of Existing Credit Facility.

Upon execution and delivery of this Agreement by each of the parties hereto and satisfaction of the conditions precedent set forth in Section 3.1, (i) the Existing Credit Facility shall be deemed terminated, and (ii) no Lender (as defined in the Existing Credit Agreement) shall have any further obligation with respect to the Existing Credit Facility. Notwithstanding the foregoing, the Borrower shall continue to have the obligation to pay any principal, interest, fees and other amounts remaining unpaid under the Existing Credit Facility, and the Lenders shall have no obligation to effect any Borrowing hereunder until such amounts have been paid in full or unless such amounts are paid in full by the proceeds of the first Borrowing hereunder.

Section 9.16 Headings.

Article and Section headings in this Agreement are included herein for convenience of reference only and shall not constitute a part of this Agreement for any other purpose.

Signature pages follow.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective officers thereunto duly authorized as of the date first above written.

MDU RESOURCES GROUP, INC.

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

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Administrative Agent and a Lender

By /s/ Keith Luettel
Its Keith Luettel
Vice President
Wells Fargo Bank, National Association

Signature Page to MDU Resources Group, Inc. Credit Agreement

UNION BANK, N.A.

/s/ Eric Otieno

By Eric Otieno

Its Assistant Vice President

Signature Page to MDU Resources Group, Inc. Credit Agreement

PNC BANK, NATIONAL ASSOCIATION

By /s/Susan J. Dimmick
Its Senior Vice President

Signature Page to MDU Resources Group, Inc. Credit Agreement

U.S. BANK NATIONAL ASSOCIATION

By /s/ John Prigge
Its John Prigge
Vice President

Signature Page to MDU Resources Group, Inc. Credit Agreement

EXHIBITS AND SCHEDULES

Exhibit A	Commitments and Addresses
Exhibit B	Form of Revolving Note
Exhibit C	Form of Compliance Certificate
Exhibit D	Assignment Certificate
Exhibit E-1	Form of General Counsel Opinion
Exhibit E-2	Form of Cohen Tauber Spievack & Wagner P.C. Opinion
Exhibit F	Form of Borrowing Opinion

Schedule 4.2	Authorizing Orders
Schedule 4.4	Subsidiaries
Schedule 6.1	Permitted Liens

Exhibit A

REVOLVING COMMITMENTS AND ADDRESSES

Name	**Revolving Commitment**	**Notice Address**
MDU Resources Group, Inc.	N/A	1200 West Century Avenue Bismarck, ND 58503 Attention: Doug Mahowald, Treasurer Telecopier: 701-530-1734 E-Mail: Doug.Mahowald@MDUResources.com
Wells Fargo Bank, National Association, as Administrative Agent	N/A	1525 W WT Harris Boulevard Mail Code: D1109-019 Attention: Syndication Agency Services Charlotte, NC 28262 Telecopier: 704-590-2790 E-Mail: cathy.burke@wachovia.com *with a copy to:* MAC N9305-070 90 South Seventh Street Minneapolis, MN 55402 Attention: Patrick McCue Telecopier: 612-316-0506 E-Mail: patrick.mccue@wellsfargo.com
Wells Fargo Bank, National Association, as a Lender	$27,500,000	MAC N9305-070 90 South Seventh Street Minneapolis, MN 55402 Attention: Patrick McCue Telecopier: 612-316-0506 E-Mail: patrick.mccue@wellsfargo.com
Union Bank, N.A.	$27,500,000	445 S. Figueroa Street, 15th Floor Los Angeles, CA 90071 Attention: Kevin Zitar Telecopier: 213-236-4096 E-Mail: kevin.zitar@unionbank.com
PNC Bank NA	$22,500,000	Three PNC Plaza 225 Fifth Avenue 4th Floor Pittsburgh PA 15222 Attention: Susan Dimmick Telecopier: 412-705-3232 E-Mail: Susan.dimmick@pnc.com
U.S. Bank National Association	$22,500,000	800 Nicollet Mall Minneapolis, MN 55402 Attention: John Prigge Telecopier: 612-303-2265 E-Mail: John.prigge@usbank.com

Exhibit B

PROMISSORY NOTE

$__________________________ ________________, 20__

For value received, MDU Resources Group, Inc., a Delaware corporation (the **"Borrower"**), promises to pay to the order of ________________________________ (the **"Lender"**), at such place as the Administrative Agent under the Credit Agreement defined below may from time to time designate in writing, in lawful money of the United States of America and in immediately available funds, the principal sum of _____________________________ ($_____________________________), or so much thereof as is advanced by the Lender to the Borrower pursuant to Section 2.1 of the Credit Agreement dated May 26, 2011 among the Borrower, Wells Fargo Bank, National Association, as Administrative Agent (in such capacity, the **"Administrative Agent"**), and various Lenders, including the Lender (together with all amendments, modifications and restatements thereof, the **"Credit Agreement"**), and to pay interest on the principal balance of this Note outstanding from time to time at the rate or rates determined pursuant to the Credit Agreement.

This Note is issued pursuant to, and is subject to, the Credit Agreement, which provides (among other things) for the amount and date of payments of principal and interest required hereunder, for the acceleration of the maturity hereof upon the occurrence of an Event of Default (as defined therein) and for the voluntary prepayment hereof. This Note is a Note, as defined in the Credit Agreement.

The Borrower shall pay all costs of collection, including reasonable attorneys' fees and legal expenses, if this Note is not paid when due, whether or not legal proceedings are commenced.

Presentment or other demand for payment, notice of dishonor and protest are expressly waived.

MDU RESOURCES GROUP, INC.

By _________________________________

Its _______________________________

Exhibit C

COMPLIANCE CERTIFICATE

______________________, _____

Wells Fargo Bank, National Association
MAC N9305-031
Minneapolis, Minnesota 55479

The Lenders, as defined in the Credit Agreement described below

Compliance Certificate

Ladies and Gentlemen:

Reference is made to the Credit Agreement (the **"Credit Agreement"**) dated May 26, 2011 entered into among MDU Resources Group, Inc. (the **"Borrower"**), Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders, as defined therein.

All terms defined in the Credit Agreement and not otherwise defined herein shall have the meanings given them in the Credit Agreement.

This is a Compliance Certificate submitted in connection with the Borrower's financial statements (the **"Statements"**) as of ____________________, _______ (the **"Effective Date"**).

I hereby certify to you as follows:

1. I am the chief financial officer of the Borrower, and I am familiar with the financial statements and financial affairs of the Borrower.

2. The Statements have been prepared in accordance with GAAP, except for any portion thereof provided pursuant to Section 5.1(b)(ii), which have been prepared in accordance with FERC Accounting Principles.

3. The computations attached hereto have been prepared in accordance with GAAP and set forth the Borrower's compliance or non-compliance with the requirements set forth in the Financial Covenants as of the Effective Date. Such computations below have been prepared from, and on a basis consistent with, the Statements. Further attached hereto are all relevant facts in reasonable detail to evidence, and the computations of, the financial covenants referred to above.

4. I have no knowledge of the occurrence of any Default or Event of Default under the Credit Agreement, except as set forth in the attachments, if any, hereto.

Very truly yours,

____

Attachment to Compliance Certificate
MDU Resources Group, Inc.

Effective Date: _______________

Section 6.11 Consolidated Total Leverage Ratio	**Actual**		**Required**
Funded Debt of Borrower and all Subsidiaries (consolidated):			
(i) indebtedness for borrowed money	$_______		
(ii) other indebtedness evidenced by notes, etc.	$_______		
(iii) capitalized lease obligations	$_______		
(iv) non-recourse secured obligations	$_______		
(v) letters of credit, etc.	$_______		
(vi) sale-and-leaseback arrangements	$_______		
(vii) interest rate/currency agreements	$_______		
(viii) guaranty obligations	$_______		
Total	$_______		
Capitalization of Borrower and Subsidiaries (consolidated)	$_______		
Total Funded Debt : Capitalization		____: 1	≤ 0.65 : 1
Section 6.12 Borrower Leverage Ratio			
Funded Debt of Borrower alone (including divisions but excluding Subsidiaries)			
(i) indebtedness for borrowed money	$_______		
(ii) other indebtedness evidenced by notes, etc.	$_______		
(iii) capitalized lease obligations	$_______		
(iv) non-recourse secured obligations	$_______		
(v) letters of credit, etc.	$_______		
(vi) sale-and-leaseback arrangements	$_______		
(vii) interest rate/currency agreements	$_______		
(viii) guaranty obligations	$_______		
Total	$_______		
Capitalization of Borrower alone (including divisions but excluding Subsidiaries)	$_______		
Borrower Funded Debt : Capitalization		____: 1	≤ 0.65 : 1

Exhibit D

Assignment and Assumption

This Assignment and Assumption (the **"Assignment and Assumption"**) is dated as of the Effective Date set forth below and is entered into by and between [the][each][1] Assignor identified in item 1 below ([the][each, an] **"Assignor"**) and [the][each][2] Assignee identified in item 2 below ([the][each, an] **"Assignee"**). [It is understood and agreed that the rights and obligations of [the Assignors][the Assignees][3] hereunder are several and not joint.][4] Capitalized terms used but not defined herein shall have the meanings given to them in the Credit Agreement identified below (as amended, the **"Credit Agreement"**), receipt of a copy of which is hereby acknowledged by [the][each] Assignee. The Standard Terms and Conditions set forth in Annex 1 attached hereto are hereby agreed to and incorporated herein by reference and made a part of this Assignment and Assumption as if set forth herein in full.

For an agreed consideration, [the][each] Assignor hereby irrevocably sells and assigns to [the Assignee][the respective Assignees], and [the][each] Assignee hereby irrevocably purchases and assumes from [the Assignor][the respective Assignors], subject to and in accordance with the Standard Terms and Conditions and the Credit Agreement, as of the Effective Date inserted by the Administrative Agent as contemplated below (i) all of [the Assignor's][the respective Assignors'] rights and obligations in [its capacity as a Lender][their respective capacities as Lenders] under the Credit Agreement and any other documents or instruments delivered pursuant thereto to the extent related to the amount and percentage interest identified below of all of such outstanding rights and obligations of [the Assignor][the respective Assignors] under the respective facilities identified below (including without limitation any letters of credit, guarantees, and swingline loans included in such facilities) and (ii) to the extent permitted to be assigned under applicable law, all claims, suits, causes of action and any other right of [the Assignor (in its capacity as a Lender)][the respective Assignors (in their respective capacities as Lenders)] against any Person, whether known or unknown, arising under or in connection with the Credit Agreement, any other documents or instruments delivered pursuant thereto or the loan transactions governed thereby or in any way based on or related to any of the foregoing, including, but not limited to, contract claims, tort claims, malpractice claims, statutory claims and all other claims at law or in equity related to the rights and obligations sold and assigned pursuant to clause (i) above (the rights and obligations sold and assigned by [the][any] Assignor to [the][any] Assignee pursuant to clauses (i) and (ii) above being referred to herein collectively as [the][an] **"Assigned Interest"**). Each such sale and assignment is without recourse to [the][any] Assignor and, except as expressly provided in this Assignment and Assumption, without representation or warranty by [the][any] Assignor.

1. Assignor[s]: ____

____

2. Assignee[s]: ____

____

---

1 For bracketed language here and elsewhere in this form relating to the Assignor(s), if the assignment is from a single Assignor, choose the first bracketed language. If the assignment is from multiple Assignors, choose the second bracketed language.

2 For bracketed language here and elsewhere in this form relating to the Assignee(s), if the assignment is to a single Assignee, choose the first bracketed language. If the assignment is to multiple Assignees, choose the second bracketed language.

3 Select as appropriate.

4 Include bracketed language if there are either multiple Assignors or multiple Assignees.

3. Borrower(s): ______________________________

4. Administrative Agent: ______________________, as the administrative agent under the Credit Agreement

5. Credit Agreement: Credit Agreement dated as of May 26, 2011 among MDU Resources Group, Inc., the Lenders parties thereto, Wells Fargo Bank, National Association, as Administrative Agent, and the other agents parties thereto

6. Assigned Interest[s]:

Assignor[s][5]	Assignee[s][6]	Facility Assigned[7]	Aggregate Amount of Commitment/ Loans for all Lenders[8]	Amount of Commitment/ Loans Assigned[8]	CUSIP Number
			$	$	
			$	$	
			$	$	

[7. Trade Date: ______________][9]

---

[5] List each Assignor, as appropriate.

[6] List each Assignee, as appropriate.

[7] Fill in the appropriate terminology for the types of facilities under the Credit Agreement that are being assigned under this Assignment (e.g. "Revolving Credit Commitment," "Term Loan Commitment," etc.)

[8] Amount to be adjusted by the counterparties to take into account any payments or prepayments made between the Trade Date and the Effective Date.

[9] To be completed if the Assignor(s) and the Assignee(s) intend that the minimum assignment amount is to be determined as of the Trade Date.

Effective Date: _____________ ___, 20___ [TO BE INSERTED BY ADMINISTRATIVE AGENT AND WHICH SHALL BE THE EFFECTIVE DATE OF RECORDATION OF TRANSFER IN THE REGISTER THEREFOR.]

The terms set forth in this Assignment and Assumption are hereby agreed to:

ASSIGNOR[S][10]

[NAME OF ASSIGNOR]

By:______________________________
Title:

[NAME OF ASSIGNOR]

By:______________________________
Title:

ASSIGNEE[S][11]

[NAME OF ASSIGNEE]

By:______________________________
Title:

[NAME OF ASSIGNEE]

By:______________________________
Title:

[Consented to and][12] Accepted:

[NAME OF ADMINISTRATIVE AGENT], as
Administrative Agent

By_________________________________
Title:

[Consented to:][13]

10 Add additional signature blocks as needed.

11 Add additional signature blocks as needed.

12 To be added only if the consent of the Administrative Agent is required by the terms of the Credit Agreement.

[NAME OF RELEVANT PARTY]

By______________________________
Title:

[13] To be added only if the consent of the Borrower and/or other parties (e.g. Swingline Lender, Letter of Credit Issuer) is required by the terms of the Credit Agreement.

ANNEX 1

STANDARD TERMS AND CONDITIONS FOR
ASSIGNMENT AND ASSUMPTION

1. Representations and Warranties.

1.1 Assignor[s]. [The][Each] Assignor (a) represents and warrants that (i) it is the legal and beneficial owner of [the][the relevant] Assigned Interest, (ii) [the][such] Assigned Interest is free and clear of any lien, encumbrance or other adverse claim and (iii) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby; and (b) assumes no responsibility with respect to (i) any statements, warranties or representations made in or in connection with the Credit Agreement or any other Loan Document, (ii) the execution, legality, validity, enforceability, genuineness, sufficiency or value of the Loan Documents or any collateral thereunder, (iii) the financial condition of the Borrower, any of its Subsidiaries or Affiliates or any other Person obligated in respect of any Loan Document or (iv) the performance or observance by the Borrower, any of its Subsidiaries or Affiliates or any other Person of any of their respective obligations under any Loan Document.

1.2. Assignee[s]. [The][Each] Assignee (a) represents and warrants that (i) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby and to become a Lender under the Credit Agreement, (ii) it meets all the requirements to be an assignee under Section 9.6(b)(iv) and (v) of the Credit Agreement (subject to such consents, if any, as may be required under Section 9.6(b)(ii) of the Credit Agreement), (iii) from and after the Effective Date, it shall be bound by the provisions of the Credit Agreement as a Lender thereunder and, to the extent of [the][the relevant] Assigned Interest, shall have the obligations of a Lender thereunder, (iv) it is sophisticated with respect to decisions to acquire assets of the type represented by the Assigned Interest and either it, or the person exercising discretion in making its decision to acquire the Assigned Interest, is experienced in acquiring assets of such type, (v) it has received a copy of the Credit Agreement, and has received or has been accorded the opportunity to receive copies of the most recent financial statements delivered pursuant to Section 5.1 thereof, as applicable, and such other documents and information as it deems appropriate to make its own credit analysis and decision to enter into this Assignment and Assumption and to purchase [the][such] Assigned Interest, (vi) it has, independently and without reliance upon the Administrative Agent or any other Lender and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Assignment and Assumption and to purchase [the][such] Assigned Interest, and (vii) if it is a Foreign Lender, attached to the Assignment and Assumption is any documentation required to be delivered by it pursuant to the terms of the Credit Agreement, duly completed and executed by [the][such] Assignee; and (b) agrees that (i) it will, independently and without reliance on the Administrative Agent, [the][any] Assignor or any other Lender, and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Loan Documents, and (ii) it will perform in accordance with their terms all of the obligations which by the terms of the Loan Documents are required to be performed by it as a Lender.

2. Payments. From and after the Effective Date, the Administrative Agent shall make all payments in respect of [the][each] Assigned Interest (including payments of principal, interest, fees and other amounts) to [the][the relevant] Assignor for amounts which have accrued to but excluding the Effective Date and to [the][the relevant] Assignee for amounts which have accrued from and after the Effective Date.

3. General Provisions. This Assignment and Assumption shall be binding upon, and inure to the benefit of, the parties hereto and their respective successors and assigns. This Assignment and Assumption may be executed in any number of counterparts, which together shall constitute one instrument. Delivery of an executed counterpart of a signature page of this Assignment and Assumption by telecopy shall be effective as delivery of a manually executed counterpart of this Assignment and Assumption. This Assignment and Assumption shall be governed by, and construed in accordance with, the law of the State of New York.

Exhibit E-1

___________, 2011

Wells Fargo Bank, National Association, as
Administrative Agent and as a Lender,
and the Other Financial Institutions Listed on
Schedule A Hereto

Ladies and Gentlemen:

I am the General Counsel of MDU Resources Group, Inc., a Delaware corporation (the **"Company"**), and in such capacity, I am familiar with (a) the negotiation, preparation, execution and delivery of that certain Credit Agreement, dated as of May 26, 2011 (the **"Agreement"**), by and among the Company, the several financial institutions from time to time party thereto, and Wells Fargo Bank, National Association, as Administrative Agent, and (b) the negotiation, preparation, execution and delivery of the other Loan Documents listed on Schedule B hereto (together with the Agreement, the **"Loan Documents"**). This opinion is furnished to you pursuant to Section 3.1(d) of the Agreement and at the instruction of the Company. All capitalized terms used but not otherwise defined herein have the meanings ascribed thereto in the Agreement.

For the purpose of rendering the opinions contained herein, I have examined and reviewed the Agreement and the other Loan Documents. I have also examined the originals, or copies certified to my satisfaction, of the Restated Certificate of Incorporation and By-Laws of the Company, resolutions adopted by the Board of Directors of the Company authorizing the execution, delivery and performance by the Company of the Agreement and the other Loan Documents, and such other corporate records of the Company and agreements, instruments and other documents as I have deemed necessary as a basis for the opinions expressed below. In my examination, I have assumed the genuineness of all signatures, other than the signatures of the Company on the Loan Documents to which it is a party, the legal capacity of natural persons, the authenticity of all documents submitted to me as originals and the conformity with original documents of all documents submitted to me as certified or photostatic copies. I have also assumed, with your consent, the due execution and delivery, pursuant to due authorization, of the Agreement by all parties thereto other than the Company and the validity and binding effect of the Agreement upon such parties.

As to any facts that I did not independently establish or verify, I have relied without independent investigation upon statements, representations and certificates of officers of the Company and as to the matters addressed therein, upon certificates or communications from public officials. As used herein, the phrase "to my knowledge" with respect to the existence or absence of facts is intended to signify that, while I have made no specific inquiry or other independent examination to determine the existence or absence of such facts, no factual information has come to my attention which causes me to believe that such facts are not accurate.

Based on and subject to the foregoing and upon such investigation as I have deemed necessary, and subject to the qualifications set forth below, it is my opinion that:

1. The Company is a corporation duly incorporated, validly existing and in good standing under the laws of Delaware.

2. The Company is duly qualified as a foreign corporation to transact business and is in good standing in Minnesota, Montana, North Dakota and South Dakota, and is not required, whether

by reason of ownership or leasing of property or the conduct of its business, to be qualified in any other jurisdiction, except where the failure so to qualify or to be in good standing would not result in a Material Adverse Effect.

3. The Company has the corporate power and authority to execute, deliver and perform its obligations under the Agreement and the other Loan Documents applicable to it, and has all requisite corporate power and authority, licenses and permits to own its assets and to carry on its business as currently conducted and as contemplated to be conducted by the Agreement.

4. The execution, delivery and performance by the Company of the Agreement and each of the other Loan Documents to which it is a party have been duly authorized by all necessary corporate action and by all necessary public utility commissions and other regulatory bodies having jurisdiction over the Company (except as noted in Schedule 4.2 of the Agreement with respect to Borrowings made after December 13, 2012), and each of the Agreement and the other Loan Documents has been duly executed and delivered by the Company.

5. The execution, delivery and performance by the Company of the Agreement and of the other Loan Documents to which it is a party do not and will not (a) require any consent or approval of the stockholders of the Company or any authorization, consent or approval by any governmental department, commission, board, bureau, agency or instrumentality, other than Authorizing Orders set forth in Schedule 4.2 to the Agreement that (except as noted therein with respect to Borrowings made after December 13, 2012) have been obtained and are in full force and effect, (b) violate any provision of any law, rule or regulation or any order, writ, injunction or decree presently in effect having applicability to the Company or the Restated Certificate of Incorporation or By-Laws of the Company, (c) result in a breach of or constitute a default under any indenture or loan or credit agreement or any other agreement, lease or instrument to which the Company is a party or by which its properties may be bound or affected, or (d) except as provided therein, result in, or require, the creation or imposition of any Lien or other charge or encumbrance of any nature upon or with respect to any of its properties.

6. Except as set forth in the Company's Annual Report on Form 10-K for the year ended December 31, 2010, or in any document subsequently filed by the Company pursuant to Section 13, 14 or 15(d) of the Exchange Act, there are no actions, suits or proceedings pending or, to my knowledge, threatened against or affecting the Company or the properties of the Company before any court or governmental department, commission, board, bureau, agency or instrumentality, which, if determined adversely to the Company, would have a Material Adverse Effect.

The opinions expressed herein are limited to the laws of the State of North Dakota and the General Corporation Law of the State of Delaware. I am a member of the Minnesota and North Dakota Bars and do not hold myself out as an expert on the laws of the States of Montana, South Dakota or Wyoming, but have made a study through counsel located in such jurisdictions or otherwise of the laws of such jurisdictions insofar as such laws are involved in the conclusions expressed in this opinion. Insofar as the opinions expressed herein relate to the General Corporation Law of the State of Delaware, or the federal laws of the United States of America, I have relied with your consent on the opinion, of even date herewith, of Cohen Tauber Spievack & Wagner P.C.

This opinion is intended solely for your use and is rendered solely in connection with the Agreement and the other Loan Documents, and without my written consent may not be (a) relied upon by you for any other purpose, or (b) relied upon by any other person or entity for any purpose, except that Cohen Tauber Spievack & Wagner P.C., special counsel to the Company, may rely on the opinions expressed herein in rendering to you their opinion of even date herewith. The opinions expressed above are limited to the law and facts in effect on the date hereof. I disclaim any obligation to advise you of facts, circumstances, events or developments which hereafter may be brought to my attention and which might alter, affect or modify the opinions expressed herein.

I hereby consent to reliance by the Administrative Agent and the Lenders now or hereafter parties to the Agreement on the opinions expressed herein.

Very truly yours,

Exhibit E-2

___________, 2011

Wells Fargo Bank, National Association, as
Administrative Agent and as a Lender,
and the Other Financial Institutions Listed on
Schedule A Hereto

Ladies and Gentlemen:

We have acted as special counsel for MDU Resources Group, Inc., a Delaware corporation (the **"Company"**), in connection with (a) the negotiation, preparation, execution and delivery of that certain Credit Agreement, dated as of May 26, 2011 (the **"Agreement"**), by and among the Company, the several financial institutions from time to time party thereto, and Wells Fargo Bank, National Association, as Administrative Agent, and (b) the negotiation, preparation, execution and delivery of the other Loan Documents listed on Schedule B hereto (together with the Agreement, the **"Loan Documents"**). This opinion is furnished to you pursuant to Section 3.1(d) of the Agreement and at the instruction of the Company. All capitalized terms used but not otherwise defined herein have the meanings ascribed thereto in the Agreement.

For the purpose of rendering the opinions contained herein, we have examined and reviewed the Agreement and the other Loan Documents. We have also examined the originals, or copies certified to our satisfaction, of the Restated Certificate of Incorporation and By-Laws of the Company, resolutions adopted by the Board of Directors of the Company authorizing the execution, delivery and performance by the Company of the Agreement and the other Loan Documents, and such other corporate records of the Company and agreements, instruments and other documents as we have deemed necessary as a basis for the opinions expressed below. In our examination, we have assumed the genuineness of all signatures, the legal capacity of natural persons, the authenticity of all documents submitted to us as originals and the conformity with original documents of all documents submitted to us as certified or photostatic copies. We have also assumed, with your consent, the due execution and delivery, pursuant to due authorization, of the Agreement by all parties thereto other than the Company and the validity and binding effect of the Agreement upon such parties. As to any facts that we did not independently establish or verify, we have relied without independent investigation upon statements, representations and certificates of officers of the Company and as to the matters addressed therein, upon certificates or communications from public officials.

Based on and subject to the foregoing and upon such investigation as we have deemed necessary, and subject to the qualifications set forth below, it is our opinion that:

1. The Company is a corporation duly incorporated, validly existing and in good standing under the laws of Delaware.

2. The Company has the corporate power and authority to execute, deliver and perform its obligations under the Agreement and the other Loan Documents applicable to it.

3. The execution, delivery and performance by the Company of the Agreement and each of the other Loan Documents to which it is a party have been duly authorized by all necessary corporate action, and each of the Agreement and the other Loan Documents has been duly executed and delivered by the Company.

4. The execution, delivery and performance by the Company of the Agreement and of the other Loan Documents to which it is a party do not and will not (a) require any consent or approval of the stockholders of the Company or any authorization, consent or approval by any governmental department, commission, board, bureau, agency or instrumentality, other than Authorizing Orders set forth in Schedule 4.2 to the Agreement that (except as noted therein with respect to Borrowings made after December 31, 2012) have been obtained and are in full force and effect, or (b) violate any provision of any law, rule or regulation or any order, writ, injunction or decree presently in effect having applicability to the Company or the Restated Certificate of Incorporation or By-Laws of the Company.

5. Each of the Agreement and each of the Loan Documents to which the Company is a party constitutes a legal, valid and binding obligation of the Company enforceable in accordance with its respective terms, subject to the effect of any applicable bankruptcy, insolvency, moratorium or other similar laws affecting creditors' rights generally and of general principles of equity (regardless of whether applied in a proceeding in equity or at law), except that we express no opinion as to (a) Section 7.3 of the Agreement, (b) the enforceability of rights to indemnify under federal or state securities laws, or (c) the enforceability of waivers of the parties of their respective rights and remedies under law.

This opinion is limited to the laws of the State of New York, the General Corporation Law of the State of Delaware, and the federal laws of the United States of America. We express no opinion as to the laws of any other jurisdiction.

In rendering this opinion, we have relied as to all matters of Minnesota, Montana, North Dakota, South Dakota and Wyoming law, as to matters addressed therein, with your consent, upon the opinion of Paul K. Sandness, Bismarck, North Dakota, the General Counsel of the Company.

This opinion is intended solely for your use and is rendered solely in connection with the Agreement and the other Loan Documents, and without our written consent may not be (a) relied upon by you for any other purpose, or (b) relied upon by any other person or entity for any purpose, except that Paul K. Sandness may rely on the opinions expressed herein in rendering to you his opinion of even date herewith.

The opinions expressed above are limited to the law and facts in effect on the date hereof. We disclaim any obligation to advise you of facts, circumstances, events or developments which hereafter may be brought to our attention and which might alter, affect or modify the opinions expressed herein.

We hereby consent to reliance by the Administrative Agent and the Lenders now or hereafter parties to the Agreement on the opinions expressed herein.

Very truly yours,

Exhibit F

BORROWING OPINION

___________, 200__

Wells Fargo Bank, National Association, as
Administrative Agent

Ladies and Gentlemen:

I am [Associate] General Counsel to MDU Resources Group, Inc., a Delaware corporation (the **"Borrower"**), and have represented the Borrower in connection with its execution and delivery of the Credit Agreement among the Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the other financial institutions party thereto, dated as of May 26, 2011 (the **"Agreement"**), and in connection with the request of the Borrower under the Agreement for a borrowing in the principal amount of $___________ to be effected on ___________, 200__ (the **"Borrowing"**). This opinion is being delivered to the Administrative Agent pursuant to Section 3.2(b) of the Agreement. All capitalized terms used and not otherwise defined herein have the meanings ascribed thereto in the Agreement.

I have examined the Loan Documents and such other matters of fact and law that I have deemed necessary in order to render this opinion. In such examination, I have assumed the genuineness of all signatures, the legal capacity of natural persons, the authenticity of all documents submitted to me as originals, the conformity to original documents of all documents submitted to me as certified or photostatic copies, and the authenticity of such latter documents.

Based upon the foregoing, it is my opinion that:

1. The Borrowing has been duly authorized by the Borrower's Board of Directors pursuant to resolutions adopted thereby on ____________, which authority remains in full force and effect on the date hereof.

2. No authorization, consent or approval by any governmental department, commission, board, bureau, agency or instrumentality, other than the Authorizing Orders which have been obtained and are in full force and effect and copies of which Authorizing Orders have been delivered to the Administrative Agent, is required in connection with the Borrowing.

3. Without limiting the generality of the foregoing, the Borrowing complies with all applicable requirements of each applicable resolution of the Borrower's Board of Directors and each applicable Authorizing Order, including but not limited to any applicable limitation on the aggregate amount of short-term or long-term debt that the Borrower may have outstanding at any one time and any limitation on the rate of interest that may be applicable thereto.

I am a member of the North Dakota Bar and do not hold myself out as an expert on the laws of any other state, but I have made a study of the laws of such states insofar as such laws are involved in the conclusions stated in this opinion.

This opinion is rendered to you in connection with the above-described transaction. This opinion may not be relied upon by you for any other purpose, or relied upon by or furnished to any other person, firm or corporation without my prior written consent.

Very truly yours,

Schedule 4.2

Authorizing Orders

MDU Resources Group, Inc. MDU Resources Group, Inc. (**"MDU"**) received authorization to issue up to $150,000,000 of short-term promissory notes representing bank borrowings and/or in the form of commercial paper from the following regulatory commissions:

a. By an order dated December 1, 2010, MDU received authorization from the Federal Energy Regulatory Commission (FERC) in Docket No. ES11-3-000. This FERC authorization is effective from December 13, 2010 through December 13, 2012.

b. By an order dated November 16, 2010, MDU received authorization from the Montana Public Service Commission in Docket No.D2010.11.103, Order No. 7119. This Montana authorization is effective from January 1, 2011 to December 31, 2012.

No further consent, approval, waiver, order or authorization of, or registration, qualification, declaration, or filings with, or notice to, any governmental department, commission, board, bureau, agency or instrumentality is required.

Schedule 4.4

SUBSIDIARIES

1. Alaska Basic Industries, Inc., an Alaska corporation, 100%
2. Ames Sand & Gravel, Inc., a North Dakota corporation, 100%
3. Anchorage Sand and Gravel Company, Inc., an Alaska corporation , 100%
4. Baldwin Contracting Company, Inc., a California corporation, 100%
5. BEH Electric Holdings, LLC, a Nevada limited liability company, 100%
6. Bell Electrical Contractors, Inc., a Missouri corporation, 100%
7. Bitter Creek Pipelines, LLC, a Colorado limited liability company, 100%
8. BMH Mechanical Holdings, LLC, a Nevada limited liability company, 100%
9. Bombard Electric, LLC, a Nevada limited liability company, 100%
10. Bombard Mechanical, LLC, a Nevada limited liability company, 100%
11. Capital Electric Construction Company, Inc., a Kansas corporation, 100%
12. Capital Electric Line Builders, Inc., a Kansas corporation, 100%
13. Cascade Natural Gas Corporation, a Washington corporation, 100%
14. Centennial Energy Holdings, Inc., a Delaware corporation, 100%
15. Centennial Energy Resources International, Inc., a Delaware corporation, 100%
16. Centennial Energy Resources LLC, a Delaware limited liability company, 100%
17. Centennial Holdings Capital LLC, a Delaware limited liability company, 100%
18. Central Oregon Redi-Mix, L.L.C., an Oregon limited liability company, 78%
19. CGC Resources, Inc., a Washington corporation, 100%
20. Concrete, Inc., a California corporation, 100%
21. Connolly-Pacific Co., a California corporation, 100%
22. Continental Line Builders, Inc., a Delaware corporation, 100%
23. Coordinating and Planning Services, Inc., a Delaware corporation, 100%
24. Desert Fire Holdings, Inc., a Nevada corporation, 100%
25. Desert Fire Protection, a Nevada Limited Partnership, 100%
26. Desert Fire Protection, Inc., a Nevada corporation, 100%
27. Desert Fire Protection, LLC, a Nevada limited liability company, 100%
28. D S S Company, a California corporation, 100%
29. E.S.I., Inc., an Ohio corporation, 100%
30. Fairbanks Materials, Inc., an Alaska corporation, 100%
31. Fidelity Exploration & Production Company, a Delaware corporation, 100%
32. Fidelity Oil Co., a Delaware corporation, 100%
33. Frebco, Inc., an Ohio corporation, 100%
34. FutureSource Capital Corp., a Delaware corporation, 100%
35. Granite City Ready Mix, Inc., a Minnesota corporation, 100%
36. Hamlin Electric Company, a Colorado corporation, 100%
37. Harp Engineering, Inc., a Montana corporation, 100%
38. Hawaiian Cement, a Hawaii partnership, 100%
39. ILB Hawaii, Inc., a Hawaii corporation, 100%
40. Independent Fire Fabricators, LLC, a Nevada limited liability company, 100%
41. Intermountain Gas Company, an Idaho corporation, 100%
42. International Line Builders, Inc., a Delaware corporation, 100%
43. InterSource Insurance Company, a Vermont corporation, 100%
44. Jebro Incorporated, an Iowa corporation, 100%
45. JTL Group, Inc., a Montana corporation, 100%
46. JTL Group, Inc., a Wyoming corporation, 100%
47. Kent's Oil Service, a California corporation, 100%
48. Knife River Corporation, a Delaware corporation, 100%

49. Knife River Corporation – North Central, a Minnesota corporation, 100%
50. Knife River Corporation – Northwest, an Oregon corporation, 100%
51. Knife River Corporation – South, a Texas corporation, 100%
52. Knife River Dakota, Inc., a Delaware corporation, 100%
53. Knife River Equipment, Inc., a Delaware corporation, 100%
54. Knife River Hawaii, Inc., a Delaware corporation, 100%
55. Knife River Marine, Inc., a Delaware corporation, 100%
56. Knife River Midwest, LLC, a Delaware limited liability company, 100%
57. KRC Holdings, Inc., a Delaware corporation, 100%
58. LME&U Holdings, LLC, a Nevada limited liability company, 100%
59. Lone Mountain Excavation & Utilities, LLC, a Nevada limited liability company, 100%
60. Loy Clark Pipeline Co., an Oregon corporation, 100%
61. LTM, Incorporated, an Oregon corporation, 100%
62. MDU Brasil Ltda., a Brazil limited liability company, 100%
63. MDU Construction Services Group, Inc., a Delaware corporation, 100%
64. MDU Energy Capital, LLC, a Delaware limited liability company, 100%
65. MDU Industrial Services, Inc., a Delaware corporation, 100%
66. MDU Resources International LLC, a Delaware limited liability company, 100%
67. MDU Resources Luxembourg I LLC S.a.r.l., a Luxembourg limited liability company, 100%
68. MDU Resources Luxembourg II LLC S.a.r.l., a Luxembourg limited liability company, 100%
69. Midland Technical Crafts, Inc., a Delaware corporation, 100%
70. Netricity LLC, an Alaska limited liability company, 75%
71. Nevada Solar Solutions, LLC, a Delaware limited liability company, 100%
72. Northstar Materials, Inc., a Minnesota corporation, 100%
73. Oregon Electric Construction, Inc., an Oregon corporation, 100%
74. Pouk & Steinle, Inc., a California corporation, 100%
75. Prairie Cascade Energy Holdings, LLC, a Delaware limited liability company, 100%
76. Prairie Intermountain Energy Holdings, LLC, a Delaware limited liability company, 100%
77. Prairielands Energy Marketing, Inc., a Delaware corporation, 100%
78. Prairielands Magnetics Limited, a Scotland private limited company, 100%
79. Rocky Mountain Contractors, Inc., a Montana corporation, 100%
80. USI Industrial Services, Inc., a Delaware corporation, 100%
81. The Wagner Group, Inc., a Delaware corporation, 100%
82. Wagner Industrial Electric, Inc., a Delaware corporation, 100%
83. The Wagner-Smith Company, an Ohio corporation, 100%
84. Wagner-Smith Equipment Co., a Delaware corporation, 100%
85. Wagner-Smith Pumps & Systems, Inc., an Ohio corporation, 100%
86. Warner Enterprises, Inc., a Nevada corporation, 100%
87. WBI Canadian Pipeline, Ltd., a Canadian corporation, 100%
88. WBI Energy Services, Inc., a Delaware corporation, 100%
89. WBI Holdings, Inc., a Delaware corporation, 100%
90. WBI Pipeline & Storage Group, Inc., a Delaware corporation, 100%
91. WHC, Ltd., a Hawaii corporation, 100%
92. Williston Basin Interstate Pipeline Company, a Delaware corporation, 100%

Schedule 6.1

LIENS

None.

MDU RESOURCES GROUP, INC.
LONG-TERM PERFORMANCE-BASED INCENTIVE PLAN

Article 1. Establishment, Purpose and Duration

1.1 *Establishment of the Plan.* MDU Resources Group, Inc., a Delaware corporation (hereinafter referred to as the "Company"), hereby establishes an incentive compensation plan to be known as the "MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan" (hereinafter referred to as the "Plan"), as set forth in this document. The Plan permits the grant of Restricted Stock, Performance Units, Performance Shares and other awards.

The Plan first became effective when approved by the stockholders at the annual meeting on April 22, 1997. The Plan, as amended, became effective on April 25, 2006 when approved by the stockholders at the 2006 annual meeting. The Plan shall remain in effect as provided in Section 1.3 herein.

1.2 *Purpose of the Plan.* The purpose of the Plan is to promote the success and enhance the value of the Company by linking the personal interests of Participants to those of Company stockholders and customers.

The Plan is further intended to provide flexibility to the Company in its ability to motivate, attract and retain the services of Participants upon whose judgment, interest and special effort the successful conduct of its operations is largely dependent.

1.3 *Duration of the Plan.* The Plan shall remain in effect, subject to the right of the Board of Directors to terminate the Plan at any time pursuant to Article 13 herein, until all Shares subject to it shall have been purchased or acquired according to the Plan's provisions.

Article 2. Definitions

Whenever used in the Plan, the following terms shall have the meanings set forth below and, when such meaning is intended, the initial letter of the word is capitalized:

2.1 *"Award"* means, individually or collectively, a grant under the Plan of Restricted Stock, Performance Units, Performance Shares or any other type of award permitted under Article 8 of the Plan.

2.2 *"Award Agreement"* means an agreement entered into by each Participant and the Company, setting forth the terms and provisions applicable to an Award granted to a Participant under the Plan.

2.3 *"Board"* or *"Board of Directors"* means the Board of Directors of the Company.

2.4 A *"Change in Control"* shall mean:

(a) The acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 20% or more of either (i) the then outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (ii) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"); provided, however, that for purposes of this subsection (a), the following acquisitions shall not constitute a Change in Control: (i) any acquisition directly from the Company, (ii) any acquisition by the Company, (iii) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company or (iv) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (c) of this Section 2.4; or

(b) Individuals who, as of April 22, 1997, which is the effective date of the Plan, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Consummation of a reorganization, merger or consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), in each case, unless, following such Business Combination, (i) all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 60% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership immediately prior to such Business Combination of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (ii) no Person (excluding any corporation resulting from such Business Combination or any employee benefit plan (or related trust) of the Company or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, 20% or more of, respectively, the then outstanding shares of common stock of the corporation resulting from such Business Combination or the combined voting power of the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (iii) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company.

For avoidance of doubt, unless otherwise determined by the Board, the sale of a subsidiary, operating entity or business unit of the Company shall not constitute a Change in Control for purposes of this Agreement.

2.5 *"Code"* means the Internal Revenue Code of 1986, as amended from time to time.

2.6 *"Committee"* means the Committee, as specified in Article 3, appointed by the Board to administer the Plan with respect to Awards.

2.7 *"Company"* means MDU Resources Group, Inc., a Delaware corporation, or any successor thereto as provided in Article 16 herein.

2.8 *"Covered Employee"* means any Participant who would be considered a "Covered Employee" for purposes of Section 162(m) of the Code.

2.9 *"Director"* means any individual who is a member of the Board of Directors of the Company.

2.10 *"Disability"* means "permanent and total disability" as defined under Section 22(e)(3)of the Code.

2.11 *"Dividend Equivalent"* means, with respect to Shares subject to an Award, a right to be paid an amount equal to dividends declared on an equal number of outstanding Shares.

2.12 *"Eligible Employee"* means an Employee who is eligible to participate in the Plan, as set forth in Section 5.1 herein.

2.13 *"Employee"* means any full-time or regularly-scheduled part-time employee of the Company or of the Company's Subsidiaries, who is not covered by any collective bargaining agreement to which the Company or any of its Subsidiaries is a party. Directors who are not otherwise employed by the Company shall not be considered Employees for purposes of the Plan. For purposes of the Plan, transfer of employment of a Participant between the Company and any one of its Subsidiaries (or between Subsidiaries) shall not be deemed a termination of employment.

2.14 *"Exchange Act"* means the Securities Exchange Act of 1934, as amended from time to time, or any successor act thereto.

2.15 *"Fair Market Value"* shall mean the average of the high and low sale prices as reported in the consolidated transaction reporting system or, if there is no such sale on the relevant date, then on the last previous day on which a sale was reported.

2.16 *"Full Value Award"* means an Award pursuant to which Shares may be issued.

2.17 *"Participant"* means an Employee of the Company who has outstanding an Award granted under the Plan.

2.18 *"Performance Goals"* means the performance goals established by the Committee, which shall be based on one or more of the following measures: sales or revenues, earnings per share, shareholder return and/or value, funds from operations, operating income, gross income, net income, cash flow, return on equity, return on capital, capital efficiency, earnings before interest, operating ratios, stock price, enterprise value, company value, asset value growth, net asset value, shareholders' equity, dividends, customer satisfaction, accomplishment of mergers, acquisitions, dispositions or similar extraordinary business transactions, safety, sustainability, profit returns and margins, financial return ratios, market performance, oil and/or gas production (growth, value and costs) and oil and/or gas reserves (including proved, probable and possible reserves and growth, value and costs) and finding and development costs. Performance goals may be measured solely on a corporate, subsidiary or business unit basis, or a combination thereof. Performance goals may reflect absolute entity performance or a relative comparison of entity performance to the performance of a peer group of entities or other external measure.

2.19 *"Performance Unit"* means an Award granted to an Employee, as described in Article 7 herein.

2.20 *"Performance Share"* means an Award granted to an Employee, as described in Article 7 herein.

2.21 *"Period of Restriction"* means the period during which the transfer of Restricted Stock is limited in some way, as provided in Article 6 herein.

2.22 *"Person"* shall have the meaning ascribed to such term in Section 3(a)(9) of the Exchange Act, as used in Sections 13(d) and 14(d) thereof, including usage in the definition of a "group" in Section 13(d) thereof.

2.23 "Qualified Restricted Stock" means an Award of Restricted Stock designated as Qualified Restricted Stock by the Committee at the time of grant and intended to qualify for the exemption from the limitation on deductibility imposed by Section 162(m) of the Code that is set forth in Section 162(m)(4)(C).

2.24 *"Restricted Stock"* means an Award of Shares granted to a Participant pursuant to Article 6 herein.

2.25 *"Shares"* means the shares of common stock of the Company.

2.26 *"Subsidiary"* means any corporation that is a "subsidiary corporation" of the Company as that term is defined in Section 424(f) of the Code.

Article 3. Administration

3.1 *The Committee.* The Plan shall be administered by the Compensation Committee of the Board, or by any other Committee appointed by the Board. The members of the Committee shall be appointed from time to time by, and shall serve at the discretion of, the Board of Directors.

3.2 *Authority of the Committee.* The Committee shall have full power except as limited by law, the Articles of Incorporation and the Bylaws of the Company, subject to such other restricting limitations or directions as may be imposed by the Board and subject to the provisions herein, to determine the size and types of Awards; to determine the terms and conditions of such Awards in a manner consistent with the Plan; to construe and interpret the Plan and any agreement or instrument entered into under the Plan; to establish, amend or waive rules and regulations for the Plan's administration; and (subject to the provisions of Article 13 herein) to amend the terms and conditions of any outstanding Award. Further, the Committee shall make all other determinations which may be necessary or advisable for the administration of the Plan. As permitted by law, the Committee may delegate its authorities as identified hereunder.

3.3 *Restrictions on Share Transferability.* The Committee may impose such restrictions on any Shares acquired pursuant to Awards under the Plan as it may deem advisable, including, without limitation, restrictions to comply with applicable Federal securities laws, with the requirements of any stock exchange or market upon which such Shares are then listed and/or traded and with any blue sky or state securities laws applicable to such Shares.

3.4 *Approval.* The Board or the Committee shall approve all Awards made under the Plan and all elections made by Participants, prior to their effective date, to the extent necessary to comply with Rule 16b-3 under the Exchange Act.

3.5 *Decisions Binding.* All determinations and decisions made by the Committee pursuant to the provisions of the Plan and all related orders or resolutions of the Board shall be final, conclusive and binding on all persons, including the Company, its stockholders, Employees, Participants and their estates and beneficiaries.

3.6 *Costs.* The Company shall pay all costs of administration of the Plan.

Article 4. Shares Subject to the Plan

4.1 *Number of Shares.* Subject to Section 4.2 herein, the maximum number of Shares that may be issued pursuant to Awards under the Plan shall be 9,242,806. Shares underlying lapsed or forfeited Awards of Restricted Stock shall not be treated as having been issued pursuant to an Award under the Plan. Shares withheld from an Award to satisfy tax withholding obligations shall be counted as Shares issued pursuant to an Award under the Plan. Shares that are potentially deliverable under an Award that expires or is canceled, forfeited, settled in cash or otherwise settled without the delivery of Shares shall not be treated as having been issued under the Plan.

Shares issued pursuant to the Plan may be (i) authorized but unissued Shares of Common Stock, (ii) treasury shares, or (iii) shares purchased on the open market.

4.2 *Adjustments in Authorized Shares.* In the event of any equity restructuring such as a stock dividend, stock split, spinoff, rights offering or recapitalization through a large, nonrecurring cash dividend, the Committee shall cause an equitable adjustment to be made (i) in the number and kind of Shares that may be delivered under the Plan, (ii) in the individual limitations set forth in Section 4.3 and (iii) with respect to outstanding Awards, in the number and kind of Shares subject to outstanding Awards, price of Shares subject to outstanding Awards, any Performance Goals relating to Shares, the market price of Shares, or per-Share results, and other terms and conditions of outstanding Awards, in the case of (i), (ii) and (iii) to prevent dilution or enlargement of rights. In the event of any other change in corporate capitalization, such as a merger, consolidation or liquidation, the Committee may, in its sole discretion, cause an equitable adjustment as described in the foregoing sentence to be made to prevent dilution or enlargement of rights. The number of Shares subject to any Award shall always be rounded down to a whole number when adjustments are made pursuant to this Section 4.2. Adjustments made by the Committee pursuant to this Section 4.2 shall be final, binding and conclusive.

4.3 *Individual Limitations.* Subject to Section 4.2 herein, (i) the total number of shares of Qualified Restricted Stock that may be granted in any calendar year to any Covered Employee shall not exceed 2,250,000 Shares; (ii) the total number of Performance Shares or Performance Units that may be granted in any calendar year to any Covered Employee shall not exceed 2,250,000 Performance Shares or Performance Units, as the case may be; (iii) the total number of Shares that are intended to qualify for deduction under Section 162(m) of the Code granted pursuant to Article 8 herein in any calendar year to any Covered Employee shall not exceed 2,250,000 Shares; (iv) the total cash Award that is intended to qualify for deduction under Section 162(m) of the Code that may be paid pursuant to Article 8 herein in any calendar year to any Covered Employee shall not exceed $6,000,000; and (v) the aggregate number of Dividend Equivalents that are intended to qualify for deduction under Section 162(m) of the Code that a Covered Employee may receive in any calendar year shall not exceed $6,000,000.

Article 5. Eligibility and Participation

5.1 *Eligibility.* Persons eligible to participate in the Plan include all officers and key employees of the Company and its Subsidiaries, as determined by the Committee, including Employees who are members of the Board, but excluding Directors who are not Employees.

5.2 *Actual Participation.* Subject to the provisions of the Plan, the Committee may, from time to time, select from all eligible Employees those to whom Awards shall be granted and shall determine the nature and amount of each Award.

Article 6. Restricted Stock

6.1 *Grant of Restricted Stock.* Subject to the terms and conditions of the Plan, Restricted Stock may be granted to
Eligible Employees at any time and from time to time, as shall be determined by the Committee.

The Committee shall have complete discretion in determining the number of shares of Restricted Stock granted to each Participant (subject to Article 4 herein) and, consistent with the provisions of the Plan, in determining the terms and conditions pertaining to such Restricted Stock.

In addition, the Committee may, prior to or at the time of grant, designate an Award of Restricted Stock as Qualified Restricted Stock, in which event it will condition the grant or vesting, as applicable, of such Qualified Restricted Stock upon the attainment of the Performance Goals selected by the Committee.

6.2 *Restricted Stock Award Agreement.* Each Restricted Stock grant shall be evidenced by a Restricted Stock Award Agreement that shall specify the Period or Periods of Restriction, the number of Restricted Stock Shares granted and such other provisions as the Committee shall determine.

6.3 *Transferability.* Restricted Stock granted hereunder may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated until the end of the applicable Period of Restriction established by the Committee and specified in the Restricted Stock Award Agreement. All rights with respect to the Restricted Stock granted to a Participant under the Plan shall be available during his or her lifetime only to such Participant or his or her legal representative.

6.4 *Certificate Legend.* Each certificate representing Restricted Stock granted pursuant to the Plan may bear a legend substantially as follows:

> "The sale or other transfer of the shares of stock represented by this certificate, whether voluntary, involuntary or by operation of law, is subject to certain restrictions on transfer as set forth in MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan and in a Restricted Stock Award

Agreement. A copy of such Plan and such Agreement may be obtained from MDU Resources Group, Inc."

The Company shall have the right to retain the certificates representing Restricted Stock in the Company's possession until such time as all restrictions applicable to such Shares have been satisfied.

6.5 *Removal of Restrictions.* Restricted Stock shall become freely transferable by the Participant after the last day of the Period of Restriction applicable thereto. Once Restricted Stock is released from the restrictions, the Participant shall be entitled to have the legend referred to in Section 6.4 removed from his or her stock certificate.

6.6 *Voting Rights.* During the Period of Restriction, Participants holding Restricted Stock may exercise full voting rights with respect to those Shares.

6.7 *Dividends and Other Distributions.* Subject to the Committee's right to determine otherwise at the time of grant, during the Period of Restriction, Participants holding Restricted Stock shall receive all regular cash dividends paid with respect to all Shares while they are so held. All other distributions paid with respect to such Restricted Stock shall be credited to Participants subject to the same restrictions on transferability and forfeitability as the Restricted Stock with respect to which they were paid and shall be paid to the Participant within forty-five (45) days following the full vesting of the Restricted Stock with respect to which such distributions were made.

6.8 *Termination of Employment.* Each Restricted Stock Award Agreement shall set forth the extent to which the Participant shall have the right to receive unvested Restricted Stock following termination of the Participant's employment with the Company and its Subsidiaries. Such provisions shall be determined in the sole discretion of the Committee, shall be included in the Restricted Stock Award Agreement entered into with Participants, need not be uniform among all grants of Restricted Stock or among Participants and may reflect distinctions based on the reasons for termination of employment.

Article 7. Performance Units and Performance Shares

7.1 *Grant of Performance Units and Performance Shares.* Subject to the terms and conditions of the Plan, Performance Units and/or Performance Shares may be granted to an Eligible Employee at any time and from time to time, as shall be determined by the Committee.

The Committee shall have complete discretion in determining the number of Performance Units and/or Performance Shares granted to each Participant (subject to Article 4 herein) and, consistent with the provisions of the Plan, in determining the terms and conditions pertaining to such Awards.

7.2 *Performance Unit/Performance Share Award Agreement.* Each grant of Performance Units and/or Performance Shares shall be evidenced by a Performance Unit and/or Performance Share Award Agreement that shall specify the number of Performance Units and/or Performance Shares granted, the initial value (if applicable), the Performance Period, the Performance Goals and such other provisions as the Committee shall determine, including but not limited to any rights to Dividend Equivalents.

7.3 *Value of Performance Units/Performance Shares.* Each Performance Unit shall have an initial value that is established by the Committee at the time of grant. The value of a Performance Share shall be equal to the Fair Market Value of a Share. The Committee shall set Performance Goals in its discretion which, depending on the extent to which they are met, will determine the number and/or value of Performance Units/Performance Shares that will be paid out to the Participants. The time period during which the Performance Goals must be met shall be called a "Performance Period."

7.4 *Earning of Performance Units/Performance Shares.* After the applicable Performance Period has ended, the holder of Performance Units/Performance Shares shall be entitled to receive a payout with respect to the Performance Units/Performance Shares earned by the Participant over the Performance Period, to be determined as a function of the extent to which the corresponding Performance Goals have been achieved.

7.5 *Form and Timing of Payment of Performance Units/Performance Shares.* Payment of earned Performance Units/Performance Shares shall be made following the close of the applicable Performance Period. The Committee, in its sole discretion, may pay earned Performance Units/Performance Shares in cash or in Shares (or in a combination thereof), which have an aggregate Fair Market Value equal to the value of the earned Performance Units/Performance Shares at the close of the applicable Performance Period. Such Shares may be granted subject to any restrictions deemed appropriate by the Committee.

7.6 *Termination of Employment.* Each Performance Unit/Performance Share Award Agreement shall set forth the extent to which the Participant shall have the right to receive a Performance Unit/Performance Share payment following termination of the Participant's employment with the Company and its Subsidiaries during a Performance Period. Such provisions shall be determined in the sole discretion of the Committee, shall be included in the Award Agreement entered into with Participants, need not be uniform among all grants of Performance Units/Performance Shares or among Participants and may reflect distinctions based on reasons for termination of employment.

7.7 *Transferability.* Except as otherwise determined by the Committee and set forth in the Performance Unit/Performance Share Award Agreement, Performance Units/Performance Shares may not be sold, transferred, pledged, assigned or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution, and a Participant's rights with respect to Performance Units/Performance Shares granted under the Plan shall be available during the Participant's lifetime only to such Participant or the Participant's legal representative.

Article 8. Other Awards

The Committee shall have the right to grant other Awards which may include, without limitation, the grant of Shares based on attainment of Performance Goals established by the Committee, the payment of Shares in lieu of cash, the payment of cash based on attainment of Performance Goals established by the Committee, and the payment of Shares in lieu of cash under other Company incentive or bonus programs. Payment under or settlement of any such Awards shall be made in such manner and at such times as the Committee may determine.

Article 9. Beneficiary Designation

Each Participant under the Plan may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom any benefit under the Plan is to be paid in case of his or her death before he or she receives any or all of such benefit. Each such designation shall revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. In the absence of any such designation, benefits remaining unpaid at the Participant's death shall be paid to the Participant's estate.

The spouse of a married Participant domiciled in a community property jurisdiction shall join in any designation of beneficiary or beneficiaries other than the spouse.

Article 10. Deferrals

The Committee may permit a Participant to defer the Participant's receipt of the payment of cash or the delivery of Shares that would otherwise be due to such Participant under the Plan. If any such deferral election is permitted, the Committee shall, in its sole discretion, establish rules and procedures for such payment deferrals.

Article 11. Rights of Employees

11.1 *Employment.* Nothing in the Plan shall interfere with or limit in any way the right of the Company to terminate any Participant's employment at any time, for any reason or no reason in the Company's sole discretion, nor confer upon any Participant any right to continue in the employ of the Company.

11.2 *Participation.* No Employee shall have the right to be selected to receive an Award under the Plan, or, having been so selected, to be selected to receive a future Award.

Article 12. Change in Control

The terms of this Article 12 shall immediately become operative, without further action or consent by any person or entity, upon a Change in Control, and once operative shall supersede and take control over any other provisions of this Plan.

Upon a Change in Control

(a) Any restriction periods and restrictions imposed on Restricted Stock, Qualified Restricted Stock or Awards granted pursuant to Article 8 (if not performance-based) shall be deemed to have expired and such Restricted Stock, Qualified Restricted Stock or Awards shall become immediately vested in full; and

(b) The target payout opportunity attainable under all outstanding Awards of Performance Units, Performance Shares and Awards granted pursuant to Article 8 (if performance-based) shall be deemed to have been fully earned for the entire Performance Period(s) as of the effective date of the Change in Control, and shall be paid out promptly in Shares or cash pursuant to the terms of the Award Agreement, or in the absence of such designation, as the Committee shall determine.

Article 13. Amendment, Modification and Termination

13.1 *Amendment, Modification and Termination.* The Board may, at any time and from time to time, alter, amend, suspend or terminate the Plan, in whole or in part, provided that no amendment shall be made which shall increase the total number of Shares that may be issued under the Plan, materially modify the requirements for participation in the Plan, or materially increase the benefits accruing to Participants under the Plan, in each case unless such amendment is approved by the stockholders.

13.2 *Awards Previously Granted.* No termination, amendment or modification of the Plan shall adversely affect in any material way any Award previously granted under the Plan, without the written consent of the Participant holding such Award, unless such termination, modification or amendment is required by applicable law and except as otherwise provided herein.

Article 14. Withholding

14.1 *Tax Withholding.* The Company shall have the power and the right to deduct or withhold, or require a Participant to remit to the Company, an amount sufficient to satisfy Federal, state and local taxes (including the Participant's FICA obligation) required by law to be withheld with respect to an Award made under the Plan.

14.2 *Share Withholding.* With respect to withholding required upon the lapse of restrictions on Restricted Stock, or upon any other taxable event arising out of or as a result of Awards granted hereunder, Participants may elect to satisfy the withholding requirement, in whole or in part, by tendering previously-owned Shares or by having the Company withhold Shares having a Fair Market Value on the date the tax is to be determined equal to the statutory total tax which could be imposed on the transaction. All elections shall be irrevocable, made in writing and signed by the Participant.

Article 15. Minimum Vesting

Notwithstanding any other provision of the Plan to the contrary, (a) the minimum vesting period for Full Value Awards with no performance-based vesting characteristics must be at least three years (vesting may occur ratably each month, quarter or anniversary of the grant date over such vesting period); (b) the minimum vesting period for Full Value Awards with performance-based vesting characteristics must be at least one year; and (c) the Committee shall not have discretion to accelerate vesting of Full Value Awards except in the event of a Change in Control or similar transaction, or the death, disability, or termination of employment of a Participant; provided, however, that the Committee may grant a "de minimis" number of Full Value Awards that do not comply with the foregoing minimum vesting standards. For this purpose "de minimis" means 331,279 Shares available for issuance as Full Value Awards under the Plan, subject to adjustment under Section 4.2 herein.

Article 16. Successors

All obligations of the Company under the Plan, with respect to Awards granted hereunder, shall be binding on any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation or otherwise, of all or substantially all of the business and/or assets of the Company.

Article 17. Legal Construction

17.1 *Gender and Number.* Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine, the plural shall include the singular and the singular shall include the plural.

17.2 *Severability.* In the event any provision of the Plan shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included.

17.3 *Requirements of Law.* The granting of Awards and the issuance of Shares under the Plan shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

17.4 *Governing Law.* To the extent not preempted by Federal law, the Plan, and all agreements hereunder, shall be construed in accordance with, and governed by, the laws of the State of Delaware.

Article 18. Accounting Restatements

This Article 18 shall apply to Awards granted to all Participants in the Plan. Notwithstanding anything in the Plan or in any Award Agreement to the contrary, if the Company's audited financial statements are restated, the Committee may, in accordance with the Company's *Guidelines for Repayment of Incentives Due to Accounting Restatements*, take such actions as it deems appropriate (in its sole discretion) with respect to

(a) Awards then outstanding (including Awards that have vested or otherwise been earned but with respect to which payment of cash or distribution of Shares, as the case may be, has not been made or deferred and also including unvested or unpaid Dividend Equivalents attributable to such outstanding Awards) ("Outstanding Awards") and

(b) vested and earned Awards, exercised stock options that were granted under the Plan prior to November 17, 2011 and any cash or Shares received with respect to Awards (including, without limitation, dividends and Dividend Equivalents), in each case to the extent payment of cash or distribution of Shares, as the case may be, was received or deferred within the 3 year period preceding the restatement ("Prior Awards"), if the terms of any such Outstanding Awards or Prior Awards or the benefits received by a Participant with respect to any such Outstanding Awards or Prior Awards (including, without limitation, dividends or Dividend Equivalents credited or distributed to a Participant and/or consideration received upon the sale of Shares that were acquired pursuant to the vesting, settlement or exercise of a Prior Award) are, or would have been, directly impacted by the restatement, including, without limitation, (i) securing (or causing to be secured) repayment of all or a portion of any amounts paid, distributed or deferred (including, without limitation, dividends or Dividend Equivalents and/or consideration received upon the sale of Shares that were acquired pursuant to the vesting, settlement or exercise of a Prior Award), (ii) granting additional Awards or making (or causing to be made) additional payments or distributions (or crediting additional deferrals) with respect to Prior Awards, (iii) rescinding vesting (including accelerated vesting) of Outstanding Awards and/or (iv) causing the forfeiture of Outstanding Awards. The Committee may, in its sole discretion, take different actions pursuant to this Article 18 with respect to different Awards, different Participants (or beneficiaries) and/or different classes of Awards or Participants (or beneficiaries). The Committee has no obligation to take any action permitted by this Article 18. The Committee may consider any factors it chooses in taking (or determining whether to take) any action permitted by this Article 18, including, without limitation, the following:

(A) The reason for the restatement of the financial statements;

(B) The amount of time between the initial publication and subsequent restatement of the financial statements; and

(C) The Participant's current employment status, and the viability of successfully obtaining repayment.

If the Committee requires repayment of all or part of a Prior Award, the amount of repayment shall be determined by the Committee based on the circumstances giving rise to the restatement. The Committee shall determine whether repayment shall be effected (i) by seeking repayment from the Participant, (ii) by reducing (subject to applicable law and the terms and conditions of the applicable plan, program or arrangement) the amount that would otherwise be provided to the Participant under any compensatory plan, program or arrangement maintained by the Company or any of its affiliates, (iii) by withholding payment of future increases in compensation (including the payment of any discretionary bonus amount) or grants of compensatory awards that would otherwise have been made in accordance with the Company's otherwise applicable compensation practices, or (iv) by any combination of the foregoing. Additionally, by accepting an Award under the Plan, Participants acknowledge and agree that the Committee may take any actions permitted by this Article 18 with respect to Outstanding Awards to the extent repayment is to be made pursuant to another plan, program or arrangement maintained by the Company or any of its affiliates.

Article 19. Code Section 409A Compliance

To the extent applicable, it is intended that this Plan and any Awards granted hereunder comply with the requirements of Section 409A of the Code and any related regulations or other guidance promulgated with respect to such Section by the U.S. Department of the Treasury or the Internal Revenue Service ("Section 409A"). Any provision that would cause the Plan or any Award granted hereunder to fail to satisfy Section 409A shall have no force or effect until amended to comply with Section 409A, which amendment may be retroactive to the extent permitted by Section 409A.

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

Section 16 Officers

Name	Title	Date of Agreement
Terry D. Hildestad	President and Chief Executive Officer, MDU Resources Group, Inc.	August 12, 2010
William E. Schneider	President and Chief Executive Officer, Knife River Corporation. Effective January 1, 2012, Executive Vice President – Bakken Development, MDU Resources Group, Inc.	August 12, 2010
John G. Harp	President and Chief Executive Officer, MDU Construction Services Group, Inc. Effective January 1, 2012, Chief Executive Officer, MDU Construction Services Group, Inc. and Knife River Corporation	August 12, 2010
Steven L. Bietz	President and Chief Executive Officer, WBI Holdings, Inc.	August 12, 2010
David L. Goodin	President and Chief Executive Officer, Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation and Intermountain Gas Company	August 12, 2010
William R. Connors	Vice President – Renewable Resources, MDU Resources Group, Inc.	August 12, 2010
Mark A. Del Vecchio	Vice President - Human Resources, MDU Resources Group, Inc.	August 12, 2010
Nicole A. Kivisto	Vice President, Controller and Chief Accounting Officer, MDU Resources Group, Inc.	August 12, 2010
Cynthia J. Norland	Vice President - Administration, MDU Resources Group, Inc.	August 12, 2010
Paul K. Sandness	General Counsel and Secretary, MDU Resources Group, Inc.	August 12, 2010
Doran N. Schwartz	Vice President and Chief Financial Officer, MDU Resources Group, Inc.	August 12, 2010
John P. Stumpf	Vice President – Strategic Planning, MDU Resources Group, Inc.	August 12, 2010
Douglass A. Mahowald	Treasurer and Assistant Secretary, MDU Resources Group, Inc.	August 12, 2010
J. Kent Wells	President and Chief Executive Officer, Fidelity Exploration & Production Company	May 2, 2011

Directors

Name	Title	Date of Agreement
Harry J. Pearce	Chairman of the Board of Directors	August 12, 2010
Terry D. Hildestad	Director	August 12, 2010
A. Bart Holaday	Director	August 12, 2010
Thomas Everist	Director	August 12, 2010
Karen B. Fagg	Director	August 12, 2010
Dennis W. Johnson	Director	August 12, 2010
Thomas C. Knudson	Director	August 12, 2010
Richard H. Lewis	Director	August 12, 2010
Patricia L. Moss	Director	August 12, 2010
John K. Wilson	Director	August 12, 2010

MDU RESOURCES

GROUP, INC.

1200 West Century Avenue
Bismarck, ND 58503

Mailing Address:
P.O. Box 5650
Bismarck, ND 58506-5650
(701) 530-1000

Terry D. Hildestad
President and
Chief Executive Officer

January 22, 2011

Mr. J. Kent Wells
18939 Camillo Court
Houston, TX 77094

Dear Kent:

Thank you for the time discussing the Fidelity Exploration & Production Company opportunity with Harry Pearce and me. We are excited to have you join our management team and have outlined the following offer of employment, conditioned upon a successful background review. Please note that as an officer subject to Section 16 of the Securities Exchange Act of 1934, your compensation will be subject to review and approval by the MDU Resources Group, Inc. Compensation Committee of the Board of Directors (the Compensation Committee) and the MDU Resources Group, Inc. Board of Directors:

Title: President and Chief Executive Officer (CEO), Fidelity Exploration & Production Company (Fidelity E&P).

Hire Date: May 2, 2011.

Reporting Relationship: This position will report to me and be a member of our Management Policy Committee.

Duties: As President and CEO of Fidelity E&P, you will perform such duties as the MDU Resources Group, Inc. Board of Directors may from time to time require which are consistent with those customarily performed by a chief executive of a business such as Fidelity E&P. You agree to devote your entire working time and energy to the interests and business of Fidelity E&P.

Base Salary: $550,000 annually, paid on a bi-weekly basis. As a Section 16 officer, your future salary will be determined by the Compensation Committee, which typically meets in November of each year to determine next year's base salaries of Section 16 officers.

Annual Incentive (Executive Incentive Compensation Plan) (EICP): Targeted amount is 100% of base salary, and actual payment will range from 0% to 200% of the targeted amount. For 2011, your EICP payment will be no less than the targeted amount and will be pro-rated by 66.67% to reflect eight (8) months of employment in 2011. Your 2011 EICP will be based on results weighted 75% for Fidelity E&P and 25% for WBI Holdings, Inc.

Long-Term Incentive Plan (LTIP): Targeted amount is 200% of base salary, and you will begin participation in the LTIP in 2012. Any payments made pursuant to the LTIP will be made in shares of MDU Resources Group, Inc. common stock.

Recruitment Incentive: As an inducement to join Fidelity E&P, we will issue a one-time lump-sum payment of $550,000, to be paid to you on or before June 3, 2011. This payment will be subject to payroll withholding tax.

Special Performance Bonus: If Fidelity E&P's fiscal year 2011 cash flow from operations is above $132,000,000, and if you do not resign from your position before January 2, 2012, we will issue you a one-time payment of $1,850,000 before March 10, 2012. The payment, after reduction for payroll withholding taxes, will be made to you one-half in MDU Resources Group, Inc. common stock and one-half in cash. We will use the closing share price on January 2, 2012, to calculate the portion of the payment remitted to you in shares of MDU Resources Group, Inc. common stock.

In the event the aforementioned 2011 cash flow level is achieved but your employment ends before January 2, 2012, due to a change in control (as defined under Section 409A of the Internal Revenue Code), the company will pay the Special Performance Bonus as outlined above.

Stock Ownership Requirement: As a senior member of management you will be required to accumulate and retain three times your base salary in MDU Resources Group, Inc. common stock over the next five years. Our expectation is that you retain shares paid to you under the LTIP and Special Performance Bonus until the stock ownership requirement is met.

Employee Benefits: You will be eligible to participate in Fidelity E&P's employee benefits package, including medical and dental insurance, 401(k), paid time off, company paid life insurance, company paid disability insurance and other benefits. A summary of Fidelity E&P's employee benefits is outlined in the attachment.

Please note that on your first paycheck dated May 20, 2011, you will begin with a vacation balance of 60 hours and in addition will begin a vacation accrual rate of

224 hours per year. The 224 hours per year represents the accrual rate for a Fidelity E&P employee with 29 years of service or higher. You will earn 8.62 hours each pay period with an accumulated vacation cap up to one and one-half times the annual rate which is equivalent to 336 hours.

Relocation: To facilitate your move from the Houston area to Denver, we are offering relocation assistance. This is outlined on the attached Relocation Summary.

Confidential Information/Non-Disclosure: You acknowledge that the business of Fidelity E&P is highly competitive and that Fidelity E&P is providing you with access to Confidential Information relating to its business. "Confidential Information" means and includes Fidelity E&P's confidential and/or proprietary information and/or trade secrets. Confidential Information includes, by way of example and without limitation, the following: (i) Fidelity E&P's trade secrets, inventions, formulas, designs, drawings, specifications and engineering or production processes; (ii) information about Fidelity E&P (or other companies within the MDU Resources Group Inc. family of companies) employees and the terms and conditions of their employment; or (iii) business plans, oil and gas data and related items. You acknowledge that this Confidential Information constitutes a valuable, special and unique asset used by Fidelity E&P in its business to obtain a competitive advantage. You further acknowledge that protection of such Confidential Information against unauthorized disclosure and use is of critical importance to Fidelity E&P in maintaining its competitive position.

You agree that you will not, at any time during or after the termination of your employment with Fidelity E&P for any reason whatsoever, make any unauthorized disclosure of any Confidential Information, or make any use of Confidential Information, except in the carrying out of your employment responsibilities on behalf of the Company or as may be required by law or a court order. You also agree to preserve and protect the confidentiality of third party Confidential Information to the same extent, and on the same basis, as Fidelity E&P's Confidential Information.

No Solicitation: You agree that for a period of two (2) years following the termination of your employment with Fidelity E&P for any reason whatsoever, you will not, directly or indirectly, solicit for employment, any person who is employed by the Company or any of its affiliates on the date of your termination or at any time within one (1) year or prior thereto; or cause, invite, solicit, entire or induce any such person to terminate his employment with the Company or any of its affiliates.

Miscellaneous: To the extent not governed by federal law, this Agreement will be construed in accordance with the laws of the State of Colorado. A waiver of any breach of or compliance with any provision of condition of this Agreement is not a waiver of similar or dissimilar provisions or conditions. The invalidity or unenforceability of any provision of this Agreement will not affect the validity or enforceability of any other provision of this Agreement, which will remain in full force and effect. This Agreement may be executed in one or more counterparts, all of which will be considered one and the same agreement.

Again, we are excited to have you on the MDU Resources Group, Inc. team and look forward to our mutual successes and accomplishments.

Sincerely,

/s/ Terry D. Hildestad

Terry D. Hildestad

I agree to the terms of
Employment as described above:

/s/ J. Kent Wells
J. Kent Wells

Date: 3/9/11

FIDELITY EXPLORATION & PRODUCTION COMPANY
SUMMARY OF EMPLOYEE BENEFITS
2011

This is a brief description of your benefits. Coverage under any of these plans is not guaranteed. The Company expects to continue the benefit plans indefinitely, but reserves the right to amend or terminate at any time.

MEDICAL

The Company offers a choice of three medical plans effective with the date of employment. The plans and premiums vary by plan design. All plans are self-funded and are administered by BlueCross BlueShield of Minnesota (BCBSMN).

The **BlueCard PPO Plan** is a managed care plan using a provider network. Services incurred are subject to a deductible, co-payment and any applicable co-insurance.

The **Consumer Preferred Health Plan** has a high-deductible that is combined with an employer-funded health reimbursement account (HRA).

The **Catastrophic Health Plan** is the same as the Consumer Preferred Health Plan without the employer-funded health reimbursement account (HRA).

Opt-Out Feature, if you elect to Opt-Out of the MDU Resources medical insurance due to other available coverage, you will receive $100/month. This taxable benefit will be included in your paycheck. If both you and your spouse are employees of the Company, the Opt-Out benefit is not available if either one of you is covered by the Company medical plan.

DENTAL

The Company offers three dental options, Dental Maintenance, Basic Dental, Dental with Orthodontia for employees to choose from effective with the date of employment. The plans are self-funded and are administered by Delta Dental.

Dental Maintenance Plan pays preventative expenses at 100% with no deductible. This plan covers only diagnostic, preventative and basic restorative benefits (cleanings, x-rays, and fillings).

Basic Dental Plan pays preventative expenses at 100% with no deductible. The deductible for all other expenses is $50 per person per year. Basic restorative expenses are paid at 80%; major restorative expenses are paid at 50%. The annual maximum benefit payable from the plan is $1,500 per person.

Dental with Orthodontia Plan pays as above with an additional $1,500 lifetime maximum orthodontia benefit per person for those under age 19.

The dental plans have a 2-year lock-in provision that requires employees to maintain coverage in the dental plan of their choice for at least two years. Upgrades are allowed at annual enrollment, but restarts the 2-year lock-in requirement. As long as you see participating dentists in the Delta Dental PPO or Premier networks, you'll take advantage of network benefits.

VISION

Vision insurance coverage is offered to employees effective with the date of employment. The vision plan is administered by VSP Vision Services. This benefit is not subsidized by the Company. As long as you see a participating VSP doctor, you'll take advantage of network benefits.

LIFE

Term life insurance coverage is offered to employees effective with the date of employment.

Non-Contributory: The Company provides at no cost to the employee one times annual earnings rounded to the next thousand to a maximum of $100,000.

Contributory: Employees can purchase additional coverage in increments of $25,000, $50,000, $100,000, $150,000, $200,000, $250,000 or $300,000 ($250,000 or $300,000 levels require Evidence of Insurability).

Dependent: Dependent life insurance for spouse and children is a voluntary benefit. The employee must be the designated beneficiary and be enrolled in Contributory Life Insurance. Employees may purchase life insurance for a spouse in increments of $15,000, $25,000, $35,000, $50,000, $100,000, or $150,000. Spousal life coverage cannot be elected at a higher amount than is currently carried by the employee.

Employees may also purchase coverage for their unmarried dependent child(ren) under age 19 or full-time students under age 25 in the amounts of $5,000 or $10,000.

VOLUNTARY ACCIDENTAL DEATH AND DISMEMBERMENT

24-hour accidental death and dismemberment coverage is offered to employees effective with the date of employment. Employees can purchase coverage in increments of $25,000, $50,000, $100,000, $150,000 or $200,000.

BUSINESS TRAVEL ACCIDENT COVERAGE

Business Travel Accident Coverage is a group insurance policy that provides 24-hour accident protection while on a company business trip. The company provides, at no cost to the employee, a principal sum coverage of $100,000.

EMPLOYEE ASSISTANCE PROGRAM

Employees and their immediate family members are eligible to utilize EAP effective with the date of employment. EAP is a confidential assessment, counseling, and referral service staffed by trained professionals who can help employees and family members evaluate their personal concerns and help them take positive action toward solving them. The first assessment of the present problem and up to seven additional sessions is at no cost to the employee.

SICK LEAVE

In the first year of employment, up to 100 hours of sick leave can be paid. A total of 200 hours of sick leave pay is available within the first two years of employment. Beyond two years of employment, sick leave can be paid for up to 180 consecutive calendar days. Eligible employees will receive 100 percent of pay up to the first 90 consecutive calendar days of approved sick leave and 80 percent of pay for any approved sick leave thereafter not to exceed 90 consecutive calendar days.

LONG TERM DISABILITY

The LTD plan is intended to help provide financial protection in the event an employee is unable to work or suffers an income loss due to a disabling condition. The LTD plan provides 60% of income if an employee continues to be disabled after a 180 day elimination period.

Replacement income is offset by other income such as workers compensation and social security benefits. Employees are eligible after completing one year of service. This plan is offered at no cost to the employee.

For employees who continue to be unable to return to work after receiving LTD benefits for a 24-month period, employment will be terminated at the end of the 24-month period. This does not affect the employee's eligibility for continued receipt of LTD benefits through the insurer.

TAX-FREE OPTIONS PLAN (TOP)

Employees are eligible to participate in TOP effective the latter of the first day of employment or the date the enrollment form is signed. Premiums paid for medical, dental and vision insurance coverage can be deducted from pay on a pre-tax basis. Also, money can be deferred to a health care and/or dependent care spending account on a pre-tax basis with the money being used for health care expenses not reimbursed by insurance or otherwise, and dependent care expenses incurred while you are at work.

401(K) PLAN

Employees are eligible to participate in the 401(k) Plan effective with the date of employment. Employees can defer up to an annual maximum amount of their income on a tax-deferred basis to this retirement plan. The company matches $.50 per dollar up to the first 6% of the employee's contribution (a 3% match). Employee and Employer matching contributions to the plan are invested as directed by each participant. Benefits are available upon termination of employment or retirement. Additionally, benefits are subject to the IRS contribution limits.

401(K) RETIREMENT CONTRIBUTION

Employees are also entitled to receive a 5% Retirement Contribution. This 5% Retirement Contribution is in addition to the current 401(k) employer match, is invested as directed by each participant, and is not dependent on employee deferrals. Additionally, benefits are subject to the IRS contribution limits.

An employee must complete a minimum of three years of vesting service to qualify for the Retirement Contribution benefit upon termination of employment or retirement. A year of vesting service is generally defined as any calendar year in which you are compensated for at least 1,000 hours of employment.

HOLIDAYS

Employees are eligible for paid scheduled holidays effective with date of employment. There are ten scheduled holidays: New Year's Day, President's Day, Good Friday, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, day after Thanksgiving, Christmas Eve Day and Christmas Day.

WORKERS COMPENSATION

Workers' Compensation insurance provides coverage for on the job accidents that result in an injury, your disability or death. It is funded 100% by employer contributions.

SOCIAL SECURITY

The amount of benefit you receive through Social Security will be based on your earnings record. You are fully insured (for the benefits your earning record qualifies you for) after completing 40 calendar quarters (10 years) in covered employment.

To determine your eligibility for Social Security and to receive an estimate of your projected retirement benefits, contact the Social Security Administration at 1-800-772-1213 or their web site: www.ssa.gov/mystatement.

The cost of this program is shared by yourself and your employer. The company contributes 6.2% of your gross income up to an annual maximum.

MEDICARE
Medicare is our country's health insurance program for individuals age 65 or older and certain individuals with disabilities.

As with Social Security, Medicare is funded equally by yourself and your employer, at 1.45% of gross income with no annual maximum.

UNEMPLOYMENT
Unemployment taxes provide benefits for qualifying unemployed persons on a national scale. It is funded 100% by employer contribution to the Federal and State government agencies.

ADDITIONAL BENEFITS
There are a number of other benefits of significant value which are part of your compensation package, including the following:

Health Reimbursement:
Recognizing that every employee has unique motivators to healthy living, wellness, and fitness, the Company has established a $150 maximum annual (calendar year) reimbursement subject to individual income taxes for any of the following health, wellness, or fitness options of the employee's choice.

- Fitness Facility Membership
- Participation in a Weight-Loss or Personal Coaching Program
- Fitness Equipment
- Resource Materials

Incentive Compensation Plan:
The Company offers an incentive compensation plan based on eligibility requirements should certain financial, safety, production and individual/team goals be met.

Training and Education Assistance:
To assist employees in their career development, the company will provide financial support for employee training and education that is beneficial to both the individual and the company.

Jury Duty:
Employees will be provided with regular pay for time served on jury duty during the employee's regularly scheduled hours of work.

Bereavement Leave:
Up to four consecutive days may be granted with pay based on the relationship of the deceased.

Military Leave:
Employees will be granted a leave of absence without pay for required military training or volunteer service. Regular full-time employees called to active duty, shall be paid the difference between military base pay and up to 40 hours per week of company pay on a straight time basis, for the tour of duty but not to exceed one year.

Service Award Program:
Employees are recognized with a service award in 5 year increments.

Relocation Benefits

You are being offered the following benefits associated with your employment as the President and CEO of Fidelity Exploration and Production Co.

House Finding - Reasonable expenses incurred for two (2) house or apartment finding trips for you and your spouse.

Temporary Living - The Company will reimburse you up to $3,000 per month for six (6) months of temporary living. Please note that this reimbursement will be made from our payroll department and will be taxable to you.

En Route Expenses - Reasonable expenses incurred during the actual move from the Houston area to the Denver location.

Moving of Household Goods and Personal Effects - The Company will pay actual and reasonable costs incurred in moving your household goods and personal effects.

Relocation Allowance - One (1) month's salary subject to normal withholding taxes.

Disposal of Current Home - We will reimburse you for the following home sale expenses:

a. Reasonable attorney's fees;

b. Federal, State, and local transfer taxes;

c. Search fees and title insurance;

d. Brokerage commission of a licensed real estate broker;

e. Mortgage prepayment penalties;

f. Recording fees;

g. Any other fees or expense approved in advance in writing by the Company.

Also, the Company will pay a bonus of three percent (3%) of the sales prices, up to a maximum of $15,000, subject to normal withholding taxes;

Acquiring a New Home - The Company will reimburse you for the following expenses associated with acquiring a new home. In order to qualify for this benefit, a new home must be purchased at the new location within eighteen (18) months of beginning work at the new location.

a. Title search and title insurance;

b. Mortgage service charges and mortgage taxes;

c. Bank applications and processing and appraisal fees;

d. Recording and notary fees;

e. State and local transfer taxes;

f. Termite inspection;

g. Land survey;

h. Attorney's fees up to a maximum of one percent (1%) of the new mortgage amount;

i. Origination fees or points up to a maximum of two percent (2%) of the new mortgage amount;

j. Any other fees or expenses approved in advance in writing by the Company.

Spouse Career Assistance - Available to your spouse in a professional position or for dual income families.

Resignation - Should you resign from the Company within one year of the movement of your household goods and personal effects to the Denver area you will be required to reimburse the Company for all payments made to you or any third parties associated with the relocation.

Note, any monies paid over and above your normal salary will be taxed at the higher IRS supplemental income rate. Additionally, reimbursement for some of the items listed above may be taxable to you.

MDU RESOURCES GROUP, INC.
LONG-TERM PERFORMANCE-BASED INCENTIVE PLAN

2011 FIDELITY PRESIDENT AND CEO AWARD AGREEMENT

J. Kent Wells
18939 Camillo Court
Houston, TX 77094

In accordance with the terms of the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan (the "Plan"), pursuant to action of the Compensation Committee of the Board of Directors of MDU Resources Group, Inc. (the "Committee"), MDU Resources Group, Inc. (the "Company") hereby grants to you (the "Participant") an opportunity to receive an incentive award (the "Award"), subject to the terms and conditions set forth in this Award Agreement (including Annex A hereto and all documents incorporated herein by reference), as set forth below:

Award:	$1,850,000, payable 50% in cash and 50% in shares of Company common stock, $1.00 par value ("Shares")
Performance Goal:	Described in Annex A
Performance Period:	January 1, 2011 through December 31, 2011 (the "Performance Period")
Date of Grant:	May 2, 2011
Dividend Equivalents:	No

THE AWARD IS SUBJECT TO FORFEITURE AS PROVIDED HEREIN. THE AWARD AND AMOUNTS RECEIVED IN CONNECTION WITH THIS AWARD ARE ALSO SUBJECT TO FORFEITURE, RECAPTURE OR OTHER ACTION IN THE EVENT OF AN ACCOUNTING RESTATEMENT, AS PROVIDED IN THE PLAN.

Further terms and conditions of the Award are set forth in Annex A hereto, which is an integral part of this Award Agreement.

All terms, provisions and conditions applicable to the Award set forth in the Plan and not set forth in this Award Agreement are hereby incorporated herein by reference. To the extent any provision hereof is inconsistent with a provision of the Plan; the provisions of the Plan will govern. The Participant hereby acknowledges receipt of a copy of this Award Agreement, including Annex A hereto, and a copy of the Plan and agrees to be bound by all the terms and provisions hereof and thereof.

MDU RESOURCES GROUP, INC.

By: /s/ Terry D. Hildestad
Terry D. Hildestad
President and
Chief Executive Officer

Agreed:

/s/ J. Kent Wells
J. Kent Wells

Attachment: Annex A

ANNEX A

TO

MDU RESOURCES GROUP, INC.
LONG-TERM PERFORMANCE-BASED INCENTIVE PLAN

2011 FIDELITY PRESIDENT AND CEO AWARD AGREEMENT

It is understood and agreed that the Award evidenced by the Award Agreement to which this is annexed is subject to the following additional terms and conditions.

1. Nature of Award. The Award represents the opportunity to earn $1,850,000 payable fifty percent (50%) in cash and fifty percent (50%) in shares of Company common stock, $1.00 par value ("Shares") if the Performance Goal is achieved during the Performance Period. The amount of cash and the number of Shares that may be earned under the Award shall be determined in accordance with Section 2 hereof.

2. Determination of Award Earned. (a)

The Performance Goal is Fidelity Exploration and Production Company's 2011 net cash provided by operating activities, as presented on the Statement of Cash Flow for the calendar year 2011. Net cash provided by operating activities must exceed $132,000,000 for 2011.

(b) If the Performance Goal is met, the amount of cash and the number of Shares earned for the Performance Period shall be determined as follows:

$$\textbf{\# of Shares} = \frac{\textbf{\$925,000}}{\textbf{Closing price of Company Common Stock on January 2, 2012}}$$

Cash = $925,000 + Closing price of Company Common Stock on January 2, 2012 for any fractional share

If the Performance Goal is not met, the Award shall be forfeited.

3. Payment of Cash and Issuance of Shares. (a) Subject to Section 5 of this Annex A, the cash earned under the Award shall be paid to the Participant in a lump sum as soon as practicable (but no later than the next March 10) following the Committee's certification of the achievement of the Performance Goal and determination of the Participant's incentive payment pursuant to Section 2 of this Annex A.

(b) Subject to any restrictions on distributions of Shares under the Plan, and subject to Section 5 of this Annex A, the Shares earned under the Award shall be issued to the Participant as soon as practicable (but no later than the next March 10) following the Committee's certification of the achievement of the Performance Goal and determination of the Participant's incentive payment pursuant to Section 2 of this Annex A.

4. Termination of Employment. Notwithstanding anything contained herein to the contrary, in order to be eligible to receive payment under this Award Agreement, the Participant must not resign from Fidelity Exploration & Production Company before January 2, 2012.

5. Tax Withholding. Pursuant to Article 16 of the Plan, the Committee shall have the power and the right to deduct or withhold from any cash or Shares earned pursuant to the Award, or require the Participant to remit to the Company, an amount sufficient to satisfy any Federal, state and local taxes (including the Participant's FICA obligations) required by law to be withheld with respect to the Award and may condition the delivery of Shares upon the Participant's satisfaction of such withholding obligations. The Participant may elect to satisfy all or part of such withholding requirement by having the Company withhold Shares having a Fair Market Value equal to the minimum statutory withholding that could be imposed on the transaction (based on minimum statutory withholding rates for Federal, state, and local tax purposes, as applicable, including payroll taxes, that are applicable to such supplemental taxable income). Such election shall be irrevocable, made in writing, signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate.

6. Ratification of Actions. By accepting the Award or other benefit under the Plan, the Participant and each person claiming under or through him shall be conclusively deemed to have indicated the Participant's acceptance and ratification of, and consent to, any action taken under the Plan or the Award by the Company, its Board of Directors, or the Committee.

7. Notices. Any notice hereunder to the Company shall be addressed to its office, 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506; Attention: Corporate Secretary, and any notice hereunder to the Participant shall be addressed to him at the address specified on the Award Agreement, subject to the right of either party to designate at any time hereafter in writing some other address.

8. Definitions. Capitalized terms not otherwise defined herein or in the Award Agreement shall have the meanings given them in the Plan.

9. Governing Law and Severability. To the extent not preempted by Federal law, the Award Agreement will be governed by and construed in accordance with the laws of the State of Delaware, without regard to conflicts of law provisions. In the event any provision of the Award Agreement shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Award Agreement, and the Award Agreement shall be construed and enforced as if the illegal or invalid provision had not been included.

10. No Rights to Continued Employment. The Award Agreement is not a contract of employment. Nothing in the Plan or in the Award Agreement shall interfere with or limit in any way the right of the Company or any Subsidiary to terminate the Participant's employment at any time, for any reason or no reason, or confer upon the Participant the right to continue in the employ of the Company or a Subsidiary.

MDU RESOURCES GROUP, INC.
NONQUALIFIED DEFINED CONTRIBUTION PLAN

WHEREAS, MDU Resources Group, Inc. (the "Company") desires to establish an unfunded plan maintained for the purpose of providing deferred compensation for a select group of management or highly compensated employees within the meaning of the United States Code of Federal Regulations Section 2520.104-23 and Sections 201(2), 301(a)(3) and 401(a)(1) of the Employee Retirement Income Security Act of 1974 ("ERISA");

NOW, THEREFORE, as approved by the Board of Directors on November 17, 2011, and effective January 1, 2012, the MDU Resources Group, Inc. Nonqualified Defined Contribution Plan (the "Plan") is hereby established as follows:

SECTION 1. PURPOSE OF PLAN

The Plan is unfunded and is maintained for the purpose of providing deferred compensation to a select group of management or highly compensated employees of the Company within the meaning of the United States Code of Federal Regulations Section 2520.104-23 and Sections 201(2), 301(a)(3) and 401(a)(1) of the ERISA. The Plan will be administered in accordance with such purpose and in accordance with the provisions of Section 409A of the Code.

SECTION 2. DEFINITIONS

<u>2.1</u> **"Administrator"** means the Compensation Committee of the Board.

<u>2.2</u> **"Beneficiary"** means the person or entity determined to be a Participant's beneficiary pursuant to Section 11.

<u>2.3</u> **"Board"** means the Board of Directors of the Company.

<u>2.4</u> **"Code"** means the Internal Revenue Code of 1986, as amended from time to time.

<u>2.5</u> **"Company"** means MDU Resources Group, Inc., and any current or future corporation that (a) is in a controlled group of corporations (within the meaning of Section 414(b) of the Code) of which MDU Resources Group, Inc. is a member and (b) has been approved by the Compensation Committee of the Board upon recommendation of the Chief Executive Officer to adopt the Plan for the benefit of its eligible employees. For purposes hereof, each such participating affiliate shall be deemed to have appointed MDU Resources Group, Inc. as its agent to act on its behalf in all matters relating to administration, amendment or termination of the Plan.

2.6 **"Compensation"** means the annualized base salary paid to a Participant as of the first day of the Plan Year.

2.7 **"ERISA"** means the Employee Retirement Income Security Act of 1974, as amended from time to time.

2.8 **"Participant"** means an employee of the Company who has been selected to participate in the Plan pursuant to Section 3.

2.9 **"Plan"** means the MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as set forth herein and as amended from time to time.

2.10 **"Plan Year"** means the calendar year.

SECTION 3. ELIGIBLE EMPLOYEES

The Administrator shall determine which management employees or highly compensated employees of the Company within the meaning of the United States Code of Federal Regulations Section 2520.104-23 and Sections 201(2), 301(a)(3) and 401(a)(1) of the ERISA shall be eligible to participate in the Plan, the eligibility waiting period (if any) and such other conditions as may be applicable from time to time. Individuals who participate in the Company's Supplemental Income Security Plan shall not be eligible to participate in the Plan. Subject to the provisions of the Plan, the Administrator may, from time to time, select from all eligible employees those who will be Participants.

SECTION 4. ACCOUNTS

The Company shall establish and maintain on its books with respect to each Participant separate account(s) which shall record (a) any Company contributions made on behalf of the Participant for a Plan Year pursuant to Section 5 below, and (b) the allocation of any hypothetical investment experience. In this regard, a separate account shall be established on behalf of a Participant for each year in which a contribution is made under the Plan.

SECTION 5. COMPANY CONTRIBUTIONS

For any Plan Year, the Administrator may elect to credit the account of any Participant designated by the Administrator an amount equal to a specified percentage of such Participant's Compensation, or a flat dollar amount. Any such credit shall be made entirely at the discretion of the Administrator and the amount of any such credit may be different for different Participants.

No employee shall have the right to be selected to receive a contribution under the Plan, or, having been so selected, to be selected to receive a future contribution.

SECTION 6. ADJUSTMENTS TO ACCOUNTS AND TAX WITHHOLDING

Each Participant's account(s) shall be reduced by the amount of any distributions to the Participant from the applicable account (including any portion of a distribution that is withheld to satisfy any federal, state, and/or local tax withholding and any social security or medicare tax withholding obligations). Pursuant to procedures established by the Administrator, each Participant's account(s) shall be adjusted as of each business day the New York Stock Exchange is open to reflect the earnings or losses of any hypothetical investment media as may be designated by the Administrator and, if applicable, elected by the Participant. Any federal, state, and/or local tax withholding and any social security or medicare tax withholding obligations may be satisfied by deducting or withholding from amounts distributed under the Plan or from other compensation payable to the Participant or by requiring the Participant to remit to the Company an amount sufficient to satisfy the federal, state, and/or local tax withholding and any social security or medicare tax withholding obligations. Additionally, to the extent social security or medicare tax withholding is required prior to the date of distribution of an amount under the Plan, to the extent permitted by Code Section 409A, the Company may satisfy such tax withholding obligations (and any additional tax withholding obligations resulting from the deemed distribution of the withheld amounts) and make a corresponding reduction in the Participant's applicable account(s).

SECTION 7. INVESTMENT OF ACCOUNTS

For purposes of determining the amount of earnings/appreciation and losses/depreciation to be credited to, or debited from, a Participant's account(s), each Participant's account(s) shall be deemed invested in the investment options (designated by the Administrator as available under the Plan) as the Participant may elect from time to time, or, if applicable, in any default investment option designated by the Administrator, in accordance with such rules and procedures as the Administrator may establish. However, no provision of the Plan shall require the Company or the Administrator to actually invest any amounts in any fund or in any other investment vehicle.

SECTION 8. VESTING

Each account of each Participant shall be subject to a separate four (4) year vesting period. With respect to a Participant's first account, if the Participant is selected to participate in the Plan with respect to a Plan Year after January 1 of that Plan Year, the Participant shall be one hundred percent (100%) vested in the amounts credited to that account after completing four (4) Years of Participation relating to that account, with the four (4) Years of Participation commencing on the date of selection as a Participant and ending at midnight on the fourth anniversary of such date of selection. With respect to a Participant's other accounts, a Participant shall be one hundred percent (100%) vested in the amounts credited to an account after completing four (4) Years of Participation relating to the account, with the four (4) Years of Participation commencing on January 1 of the Plan Year in which the contribution is made to the account and ending at midnight on January 1 four (4) years thereafter. Partial or pro rata vesting is not permitted with respect to Participants' accounts.

Subject to the provisions of Section 14, if a Participant either (a) dies or (b) is an officer of the Company, has attained age sixty-five (65), and is required to retire pursuant to the Company's bylaws prior to the end of the vesting period(s) with respect to the Participant's account(s), such Participant shall have a nonforfeitable (vested) right to 100% of the amounts credited to the Participant's account(s). If a Participant separates from service for any reason other than as described in the prior sentence, such Participant shall have a nonforfeitable (vested) right to the amounts credited to the Participant's account(s) only to the extent such amounts had vested as of the date of the separation from service.

SECTION 9. TIME AND MANNER OF DISTRIBUTION

Each Participant shall irrevocably elect, upon initial participation, and in accordance with rules and procedures prescribed by the Administrator, one of the following modes of distribution for his account(s):

(a) a single lump sum payment; or

(b) annual installments over a period of up to five (5) years, the amount of each installment to equal the balance of the Participant's vested account(s) immediately prior to the installment divided by the number of installments remaining to be paid. Each subsequent installment shall be made on the first day of the calendar month following the one (1) year anniversary of the prior payment.

For the avoidance of doubt, a Participant shall make only one election with respect to the mode of distribution of his account(s) and such election shall apply to all of the Participant's account(s). To the extent no Participant election is in effect with respect to a Participant's account(s), the Participant shall be deemed to have elected to receive such account(s) in a single lump sum payment.

Subject to the following provisions in this Section 9 and the provisions of Sections 10 and 14, distribution of a Participant's vested account(s) shall be made or commence as follows:

(i) if the Participant elected a single lump sum payment, such lump sum payment shall be made within ninety (90) days following the Participant's "separation from service" with the Company (within the meaning of Code Section 409A); or

(ii) if the Participant elected annual installments over a period of up to five (5) years, the annual installments shall commence within ninety (90) days following the Participant's "separation from service" with the Company (within the meaning of Code Section 409A) or, if later, the date the Participant attains age sixty-five (65);

provided, however that, in either case, if the Participant is a "specified employee" of the Company (as defined under Section 409A(a)(2)(B)(i) of the Code) on the date of separation from service, distribution shall not be made or commence prior to the first business day after the date that is six (6) months after the Participant's separation from service or, if earlier, within ninety (90) days following the date of the Participant's death. "Specified employees" shall be determined in accordance with the Company's *Specified Employee Policy Regarding Compensation*, which is attached as Annex A.

Notwithstanding the foregoing, payment may be delayed under any of the circumstances permitted under said Section 409A. Provided, further, that, if any amounts credited to a Participant's vested account(s) become subject to tax under Section 409A of the Code, the amount required to be included in income as a result of the failure to comply with the requirements of Code Section 409A and related Treasury Regulations shall be immediately distributed to the Participant.

Payment shall be treated as made upon the date specified under the Plan if payment is made at such date or a later date within the same taxable year of the Participant or, if later, by the fifteenth (15th) day of the third (3rd) calendar month following the specified payment date (or, if payment may be made during a specified period of time, the first date in such period), provided the Participant is not permitted, directly or indirectly, to designate the taxable year of the payment.

SECTION 10. DEATH BENEFIT

In the event of the death of a Participant while in the employ of the Company, vesting in the Participant's account(s) shall be one hundred percent (100%), if not otherwise one hundred percent (100%) vested under Section 8, with the value of the Participant's account(s) being distributed to the Participant's Beneficiary, in a single lump sum payment, within ninety (90) days following the Participant's death.

In the event a Participant dies (a) after distribution has commenced under the Plan or (b) after separation from service, but prior to the date distribution is made or commences, the vested balance of the Participant's account(s), if any, shall be distributed to the Participant's Beneficiary, in a single lump sum payment, within ninety (90) days following the Participant's death.

Payment shall be treated as made upon the date specified under the Plan if payment is made at such date or a later date within the same taxable year of the Participant or, if later, by the fifteenth (15th) day of the third (3rd) calendar month following the specified payment date (or, if payment may be made during a specified period of time, the first date in such period), provided neither the Participant nor any Beneficiary is permitted, directly or indirectly, to designate the taxable year of the payment.

SECTION 11. BENEFICIARY DESIGNATION

A Participant may designate the person or persons to whom the Participant's vested account(s) under the Plan shall be paid in the event of the Participant's death, in accordance with rules and procedures established by the Administrator. If no Beneficiary is designated, or no Beneficiary survives the Participant, payment shall be made to the Participant's surviving spouse, or if none, to the Participant's estate. If a Beneficiary survives the Participant, but dies before the balance payable to the Beneficiary has been distributed, any remaining balance shall be paid to the Beneficiary's estate.

SECTION 12. PLAN ADMINISTRATION

<u>12.1</u> **Authority of Administrator.** The Administrator is authorized to interpret and construe any provision of the Plan and any agreement or instrument entered into under the Plan, to determine eligibility and benefits under the Plan, to prescribe, amend, waive and rescind rules and regulations relating to the Plan, to adopt such forms as it may deem appropriate for the administration of the Plan, to provide for conditions and assurances deemed necessary or advisable to protect the interests of the Company and to make all other determinations necessary or advisable for the administration of the Plan, but only to the extent not contrary to the express provisions of the Plan or the provisions of Section 409A of the Code and the regulations and rulings promulgated thereunder. Determinations, interpretations or other actions made or taken by the Administrator under the Plan shall be final and binding for all purposes and upon all persons.

<u>12.2</u> **Delegation of Authority by the Board.** Notwithstanding the general authority of the Administrator to select Participants of the Plan and determine the amount of contributions to be credited to Participants' plan account(s), the Board may, by resolution, expressly delegate to one or more executive officers of the Company the authority, solely with respect to employees who are not subject to Section 16 of the Securities Exchange Act of 1934, as amended, to determine, within the parameters set forth in the Plan or established by the Board or the Administrator, the amount of any contributions to be credited to Participants' account(s) as bookkeeping entries.

<u>12.3</u> **Hold Harmless.** The Company shall indemnify, hold harmless and defend the Administrator (and its delegates) and each executive officer appointed by the Board pursuant to Section 12.2 from any liability which any of them may incur in connection with the performance of its duties in connection with this Plan, so long as the Administrator (or such delegate or executive officer) was acting in good faith and within what the Administrator (or such delegate or executive officer) reasonably understood to be the scope of its duties.

<u>12.4</u> **Appeal Procedure.**

(a) Pursuant to procedures established by the Administrator, claims for benefits under the Plan made by a Participant or Beneficiary (the "claimant") must be submitted in writing to the Administrator.

If a claim is denied in whole or in part, the Administrator shall notify the claimant within ninety (90) days after receipt of the claim (or within one hundred eighty (180) days, if special circumstances require an extension of time for processing the claim, and provided written notice indicating the special circumstances and the date by which a final decision is expected to be rendered is given to the claimant within the initial ninety (90) day period). If notification is not given in such period, the claim shall be considered denied as of the last day of such period and the claimant may request a review of the claim.

The notice of the denial of the claim shall be written in a manner calculated to be understood by the claimant and shall set forth the following:

(i) the specific reason or reasons for the denial of the claim;

(ii) the specific references to the pertinent Plan provisions on which the denial is based;

(iii) a description of any additional material or information necessary to perfect the claim, and an explanation of why such material or information is necessary; and

(iv) a statement that any appeal of the denial must be made by giving to the Administrator, within sixty (60) days after receipt of the denial of the claim, written notice of such appeal, such notice to include a full description of the pertinent issues and basis of the claim.

(b) Upon denial of a claim in whole or part, the claimant (or his duly authorized representative) shall have the right to submit a written request to the Administrator for a full and fair review of the denied claim, to be permitted to review documents pertinent to the denial, and to submit issues and comments in writing. Any appeal of the denial must be given to the Administrator within the period of time prescribed under (a)(iv) above. If the claimant (or his duly authorized representative) fails to appeal the denial to the Administrator within the prescribed time, the Administrator's adverse determination shall be final, binding and conclusive.

The Administrator may hold a hearing or otherwise ascertain such facts as it deems necessary and shall render a decision which shall be binding upon both parties. The Administrator shall advise the claimant of the results of the review within sixty (60) days after receipt of the written request for the review, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered as soon as possible but not later than one hundred twenty (120) days after receipt of the request for review. If such extension of time is required, written notice of the extension shall be furnished to the claimant prior to the commencement of the extension. The decision of the review shall be written in a manner calculated to be understood by the claimant and shall include specific reasons for the decision and specific references to the pertinent Plan provisions on which the decision is based. The decision of the Administrator shall be final, binding and conclusive.

SECTION 13. FUNDING

13.1 Plan Unfunded. The Plan is unfunded for tax purposes and for purposes of Title I of ERISA. Accordingly, the obligation of the Company to make payments under the Plan constitutes solely an unsecured (but legally enforceable) promise of the Company to make such payments, and no person, including any Participant or Beneficiary shall have any lien, prior claim or other security interest in any property of the Company as a result of this Plan. Any amounts payable under the Plan shall be paid out of the general assets of the Company and each Participant and Beneficiary shall be deemed to be a general unsecured creditor of the Company.

<u>13.2</u> Rabbi Trust. The Company may enter into a grantor trust to pay its obligations hereunder (e.g., a rabbi trust), the assets of which shall be, for all purposes, the assets of the Company. In the event the trustee of such trust is unable or unwilling to make payments directly to Participants and Beneficiaries and such trustee remits payments to the Company for delivery to Participants and Beneficiaries, the Company shall promptly remit such amount, less applicable income and other taxes required to be withheld, to the Participant or Beneficiary.

SECTION 14. FORFEITURE OF BENEFITS

Notwithstanding any provision of this Plan to the contrary, if any Participant is discharged from employment with the Company for cause due to willful misconduct, dishonesty, or conviction of a crime or felony, all as determined in the sole discretion of the Administrator, the rights of such Participant (or any Beneficiary of such Participant) to any present or future benefit under the Plan (whether or not vested) shall be forfeited, to the extent not otherwise prohibited by applicable law.

SECTION 15. AMENDMENT

The Board shall have the right to amend, suspend or terminate the Plan at any time subject to the provisions of Section 409A of the Code; provided, however, that no such action shall, without the Participant's consent, impair the Participant's right with respect to any existing vested account(s) under the Plan. Subject to the provisions of Section 14, the termination of the Plan, with respect to some or all of the Participants, and any resulting distribution of the account balances of such affected Participants, shall be made in accordance with the provisions of Section 409A of the Code and shall not constitute the impairment of such Participant's rights hereunder.

SECTION 16. NO ASSIGNMENT

A Participant's right to the amount credited to his vested account(s) under the Plan shall not be subject in any manner to anticipation, alienation, sale, transfer, assignment, pledge, encumbrance, attachment, or garnishment by creditors of the Participant or the Participant's Beneficiary.

SECTION 17. COMPANY-OWNED LIFE INSURANCE ("COLI")

<u>17.1</u> Company Owns All Rights. In the event that, in its discretion, the Company purchases a life insurance policy or policies insuring the life of any Participant to allow the Company to informally finance and/or recover, in whole or in part, the cost of providing the benefits hereunder, neither the Participant nor any Beneficiary shall have any rights whatsoever therein. The Company shall be the sole owner and beneficiary of any such policy or policies and shall possess and may exercise all incidents of ownership therein, except in the event of the establishment of and transfer of said policy or policies to a trust by the Company as described in Section 13.2 hereof.

17.2 Participant Cooperation. If the Company decides to purchase a life insurance policy or policies on any Participant, the Company shall so notify such Participant. Such Participant shall take whatever actions may be necessary to enable the Company to timely apply for and acquire such life insurance and to fulfill the requirements of the insurance carrier relative to the issuance thereof as a condition of eligibility to participate in the Plan. Any Participant who declines to supply information or to otherwise cooperate so that the Company may obtain life insurance on behalf of such Participant shall be denied participation in the Plan.

SECTION 18. SUCCESSORS AND ASSIGNS

The provisions of this Plan shall be binding upon and inure to the benefit of the Company, its successors and assigns, and the Participant, his Beneficiaries, heirs, legal representatives and assigns.

SECTION 19. NO CONTRACT OF EMPLOYMENT

Nothing contained herein shall be construed as a contract of employment between a Participant and the Company, or as a right of the Participant to continue in employment with the Company, or as a limitation of the right of the Company to discharge the Participant at any time, with or without cause.

SECTION 20. ENFORCEABILITY

If any term or condition of the Plan shall be invalid or unenforceable to any extent or in any application, then the remainder of the Plan, and such term or condition except to such extent or in such application, shall not be affected thereby, and each and every term and condition of the Plan shall be valid and enforced to the fullest extent and in the broadest application permitted by law.

SECTION 21. CONSTRUCTION

Wherever appropriate, the use of the masculine gender shall be extended to include the feminine and/or neuter, and the singular form of words extended to include the plural, or vice versa.

SECTION 22. GOVERNING LAW

This Plan shall be interpreted in a manner consistent with Code Section 409A and the guidance issued thereunder by the Department of the Treasury and the Internal Revenue Service and shall also be subject to and construed in accordance with the provisions of ERISA, where applicable, and otherwise by the laws of the State of North Dakota, without regard to the conflict of law provisions of any jurisdiction.

ANNEX A

MDU RESOURCES GROUP, INC.
Specified Employee Policy Regarding Compensation

Effective November 14, 2007, for purposes of all plans, agreements and other arrangements of MDU Resources Group, Inc. (the "Company") and its affiliates that are subject to Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"), the determination of individuals who are "specified employees," as that term is defined in Code Section 409A, shall be determined under this policy, as may be amended from time to time pursuant to paragraph 4 ("Policy").

1. **Establishment of Specified Employee List.** Between January 1st and April 1st of each calendar year, the Company shall establish a "Specified Employee List." The Specified Employee List shall become effective on April 1st of the calendar year in which the Specified Employee List is established and shall cease to be effective on March 31st of the following calendar year. Any individual who, as of his or her "separation from service" (within the meaning of Code Section 409A(a)(2)(A)(i)), is on the Specified Employee List then in effect shall be considered a "specified employee" for purposes of Section 409A.

2. **Inclusion on the Specified Employee List.** The Specified Employee List shall include all individuals who, at any time during the Determination Year, met the requirements of Code Section 416(i)(l)(A)(i), (ii) or (iii) and the related regulations (but without regard to Code Section 415(i)(5)). For this purpose, "Determination Year" shall mean the calendar year ending on the December 31st prior to the April 1st when the Specified Employee List becomes effective. For purposes of determining which individuals meet the requirements of Code Section 416(i)(l)(A)(i), (ii) or (iii) and the related regulations (but without regard to Code Section 415(i)(5)), the term gross compensation shall have the meaning set forth in the MDU Resources Group, Inc. 401(k) Retirement Plan, as may be amended from time to time (the "Retirement Plan").

3. **Delayed Payments.** If any employee is determined to be a specified employee under this Policy, any compensation to be provided to such specified employee that is required to be delayed to comply with Code Section 409A(a)(2)(B)(i) shall not be provided before the date that is six months after the date of such separation from service (or, if earlier than the end of such six-month period, the date of death of the specified employee). This Policy shall not apply to any payment that is not treated as deferred compensation under, or is otherwise excluded from, the requirements of Code Section 409A and the regulations promulgated thereunder.

4. **Changes to Policy.** The Company may amend or modify this Policy at any time; provided, however, that any changes made to the period during which the Specified Employee List is effective or the Determination Year shall not take effect for a period of at least 12 months and any changes made to the definition of compensation (either in the Policy or in the Retirement Plan) shall not be used to identify specified employees until the next Specified Employee List is established.

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

The MDU Resources Group, Inc. 401(k) Retirement Plan (as restated March 1, 2011) (the "Plan"), is hereby further amended, effective as of October 31, 2011, unless otherwise indicated, as follows:

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

Participating Affiliate	**Current Effective Date (Original Effective Date)**[2]
Anchorage Sand & Gravel Company, Inc. (excluding President)	January 1, 1999
Baldwin Contracting Company, Inc.	January 1, 1999
Bell Electrical Contractors, Inc.	January 1, 2002
Bitter Creek Pipelines, LLC[1/3]	January 1, 2010 (January 1, 2001)
Cascade Natural Gas Corporation	January 1, 2011 July 2, 2007
Concrete, Inc.	January 1, 2001
Connolly-Pacific Co.	January 1, 2007
DSS Company	January 1, 2004 (July 8, 1999)
E.S.I., Inc.	January 1, 2008 (January 1, 2003)
Fairbanks Materials, Inc.	May 1, 2008
Granite City Ready Mix, Inc.	June 1, 2002
Great Plains Natural Gas Co.	January 1, 2008

Participating Affiliate	**Current Effective Date (Original Effective Date)[2]**
Hawaiian Cement (non-union employees hired after December 31, 2005)	January 1, 2009
Intermountain Gas Company	January 1, 2011
Jebro Incorporated	November 1, 2005
Kent's Oil Service	January 1, 2007
Knife River Corporation – Northwest (the Central Oregon Division, f/k/a HTS)	January 1, 2010 (January 1, 1999)
Knife River Corporation – Northwest (the Southern Idaho Division)	January 1, 2010 (January 1, 2006)
Knife River Corporation – Northwest (the Spokane Division)	January 1, 2010 (January 1, 2006)
Knife River Corporation - South (f/k/a Young Contractors, Inc.)	January 1, 2008 (January 1, 2007)
LTM, Incorporated	January 1, 2003
Montana-Dakota Utilities Co. (including union employees)	January 1, 2008
Oregon Electric Construction, Inc.[3]	March 7, 2011
Wagner Industrial Electric, Inc.	January 1, 2008
Wagner Smith Equipment Co.	January 1, 2008 (July 1, 2000)
WBI Holdings, Inc.[1/3]	January 1, 2009
WHC, Ltd.	September 1, 2001
Williston Basin Interstate Pipeline Company[1/3]	January 1, 2009

[1]Eligible employees participating in a management incentive compensation plan

or an executive incentive compensation plan are not eligible for a Profit Sharing Contribution. Employees of the Total Corrosion Solutions division of Bitter Creek Pipelines, LLC are excluded from this feature.

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

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

Explanation: This amendment removes Frebco, Inc. (FREBCO) as a Participating Affiliate of Supplement D-1 of the K-Plan as the result of FREBCO benefit eligible employees being moved to Wagner Industrial Electric, Inc.

2. Effective January 1, 2012, by replacing the following entries in Schedule A:

Knife River Corporation – Northwest (the Southern Oregon Division, f/k/a Rogue) shall make a matching contribution equal to one hundred percent (100%) of each Southern Oregon Division employee's participating savings contribution, up to the Participant's maximum savings contributions of ten (10%) of compensation for each pay period.

Effective April 1, 1994 – December 31, 2011

****

Knife River Corporation – Northwest (the Western Oregon Division, f/k/a MBI) shall not make a matching contribution of each Western Oregon Division employee's participating savings contribution.

Effective September 1, 2004 – December 31, 2011

****

Explanation: This amendment provides an end date to the matching contribution provisions for these divisions as a result of adopting the standard match provisions of Section 3.3(a) due to standardizing retirement benefits for KRC-NW, effective January 1, 2012.

IN WITNESS WHEREOF, MDU Resources Group, Inc., as Sponsoring Employer of the Plan, has caused this amendment to be duly executed by a member of the MDU Resources Group, Inc. Employee Benefits Committee ("EBC") on this 29th day of December, 2011.

MDU RESOURCES GROUP, INC.
EMPLOYEE BENEFITS COMMITTEE

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

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

	Years Ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands of dollars)				
Earnings Available for Fixed Charges:					
Net Income (a)	$ 223,842	$ 218,205	$ (126,653)	$ 293,826	$ 308,288
Income Taxes	110,273	122,530	(96,092)	147,475	190,024
	334,115	340,735	(222,745)	441,301	498,312
Rents (b)	13,568	12,897	14,475	11,781	11,947
Interest (c)	86,505	88,930	89,943	86,320	76,248
Total Earnings Available for Fixed Charges	$ 434,188	$ 442,562	$ (118,327)	$ 539,402	$ 586,507
Preferred Dividend Requirements	$ 685	$ 685	$ 685	$ 685	$ 685
Ratio of Income Before Income Taxes to Net Income	149%	156%	176%	150%	159%
Preferred Dividend Factor on Pretax Basis	1,021	1,069	1,206	1,028	1,089
Fixed Charges (d)	106,348	107,552	109,117	101,452	90,545
Combined Fixed Charges and Preferred Stock Dividends	$ 107,369	$ 108,621	$ 110,323	$ 102,480	$ 91,634
Ratio of Earnings to Fixed Charges	4.1x	4.1x	— (e)	5.3x	6.5x
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	4.0x	4.1x	— (e)	5.3x	6.4x

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

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

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

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

(e) Due to the $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 combined fixed charges and preferred stock dividends for the twelve months ended December 31, 2009. If the $384.4 million after-tax noncash write-down is excluded, the ratio of earnings to fixed charges and the ratio of earnings to combined fixed charges and preferred stock dividends would both have been 4.6 times for the twelve months ended December 31, 2009.

The above ratios related to fixed charges and combined fixed charges and preferred stock dividends that exclude the effect of the after-tax noncash write-down of natural gas and oil properties are non-GAAP financial measures. The Company believes that these non-GAAP financial measures are 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.

MDU RESOURCES GROUP, INC.
List of Subsidiaries
(effective December 31, 2011)

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

Granite City Ready Mix, Inc.	Minnesota
Hamlin Electric Company	Colorado
Harp Engineering, Inc.	Montana
Hawaiian Cement, a partnership	Hawaii
ILB Hawaii, Inc.	Hawaii
Independent Fire Fabricators, LLC	Nevada
Intermountain Gas Company	Idaho
International Line Builders, Inc.	Delaware
InterSource Insurance Company	Vermont
Jebro Incorporated	Iowa
JTL Group, Inc., a Montana corporation	Montana
JTL Group, Inc., a Wyoming corporation	Wyoming
Kent's Oil Service	California
Knife River Corporation	Delaware
Knife River Corporation – North Central	Minnesota
Knife River Corporation – Northwest	Oregon
Knife River Corporation – South	Texas
Knife River Dakota, Inc.	Delaware
Knife River Equipment, Inc.	Delaware
Knife River Hawaii, Inc.	Delaware

Knife River Marine, Inc.	Delaware
Knife River Midwest, LLC	Delaware
KRC Holdings, Inc.	Delaware
LME&U Holdings, LLC	Nevada
Lone Mountain Excavation & Utilities, LLC	Nevada
Loy Clark Pipeline Co.	Oregon
LTM, Incorporated	Oregon
MDU Brasil Ltda.	Brazil
MDU Construction Services Group, Inc.	Delaware
MDU Energy Capital, LLC	Delaware
MDU Industrial Services, Inc.	Delaware
MDU Resources International LLC	Delaware
MDU Resources Luxembourg I LLC S.a.r.l.	Luxembourg
MDU Resources Luxembourg II LLC S.a.r.l.	Luxembourg
Midland Technical Crafts, Inc.	Delaware
Netricity LLC	Alaska
Northstar Materials, Inc.	Minnesota
Oregon Electric Construction, Inc.	Oregon
Pouk & Steinle, Inc.	California
Prairie Cascade Energy Holdings, LLC	Delaware
Prairie Intermountain Energy Holdings, LLC	Delaware
Prairielands Energy Marketing, Inc.	Delaware
Prairielands Magnetics Limited	Scotland
Rocky Mountain Contractors, Inc.	Montana
USI Industrial Services, Inc.	Delaware
Wagner Group, Inc., The	Delaware
Wagner Industrial Electric, Inc.	Delaware
Wagner-Smith Company, The	Ohio
Wagner-Smith Equipment Co.	Delaware
Wagner-Smith Pumps & Systems, Inc.	Ohio
Warner Enterprises, Inc.	Nevada
WBI Canadian Pipeline, Ltd.	Canada
WBI Energy Services, Inc.	Delaware
WBI Holdings, Inc.	Delaware
WBI Pipeline & Storage Group, Inc.	Delaware
WHC, Ltd.	Hawaii
Williston Basin Interstate Pipeline Company	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements No. 333-178042 and No. 333-174326 on Form S-3, and No. 333-27877, No. 333-118622, No. 333-114488, and No. 333-158572 on Form S-8, of our reports dated February 24, 2012, relating to the consolidated financial statements and financial statement schedules of MDU Resources Group, Inc. and subsidiaries (the “Company”) (which report expresses an unqualified opinion and includes an explanatory paragraph relating to 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), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2011.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 24, 2012

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235 TELEPHONE (713) 651-9191

CONSENT OF RYDER SCOTT COMPANY, L.P.

As independent oil and gas consultants, Ryder Scott Company, L.P. hereby consents to the incorporation by reference in Registration Statement No. 333-178042 and No. 333-174326 on Form S-3, and No. 333-27877, No. 333-118622, No. 333-114488, and No. 333-158572 on Form S-8, of all references to our firm's name and audit of portions of Fidelity Exploration & Production Company's ("Fidelity") proved natural gas and oil reserves estimates as of December 31, 2011, as described in our letter to Fidelity dated January 10, 2012, included in or made a part of MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011. Ryder Scott Company, L.P. recognizes Fidelity is an indirect wholly owned subsidiary of MDU Resources Group, Inc. who makes filings with the Securities and Exchange Commission.

/s/ RYDER SCOTT COMPANY, L.P.

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

Houston, Texas
February 24, 2012

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

CERTIFICATION

I, Terry D. Hildestad, certify that:

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

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: February 24, 2012

/s/ Terry D. Hildestad
Terry D. Hildestad
President and Chief Executive Officer

CERTIFICATION

I, Doran N. Schwartz, certify that:

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

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

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

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

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

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: February 24, 2012

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

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

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

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2011 (the "Report"), fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

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

IN WITNESS WHEREOF, each of the undersigned has executed this statement this 24th day of February, 2012.

/s/ Terry D. Hildestad
Terry D. Hildestad
President and Chief Executive Officer

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

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

MDU RESOURCES GROUP, INC.
MINE SAFETY INFORMATION

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

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

During the twelve months ended December 31, 2011, none of the Company's operating subsidiaries received citations or orders under the following sections of the Mine Safety Act: 104(d), 110(b)(2) or 104(e). The Company has 49 contests pending before administrative law judges of the Federal Mine Safety and Health Review Commission that involve 39 Section 104 S&S citations, one Section 104(b) order, eight Section 104(d) citations and one Section 107(a) order. Of the contests pending, 39 were initiated during the twelve months ended December 31, 2011, of which 37 were Section 104 S&S citations, one was a Section 104(b) order and one was a Section 107(a) order. During the twelve months ended December 31, 2011, 25 Section 104 S&S citations were resolved.

Mine or Operating Name/ MSHA Identification Number	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Total Number of Mining Related Fatalities (#)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
140 Pit	1	—	—	$ 176	—	—	—	—
Advance Aggregate	1	—	—	762	—	—	—	—
Alva	—	—	—	200	—	—	—	—
Amyx Pit	—	—	—	100	—	—	—	—
Anderson Pit	1	—	—	392	—	1	1	—
Angell Quarry	—	—	—	—	—	1	—	—
Bang Pit	—	—	—	600	—	—	—	—
Becker Portable	—	—	—	200	—	—	—	3
Becker Wash Plant #1	2	—	—	—	—	—	—	—
Bender Pit	—	—	—	—	—	—	—	2
Billings Pit	1	—	—	490	—	—	—	—
Birchwood	1	—	—	262	—	1	1	—
Coffee Lake	—	—	—	400	—	—	—	—

Mine or Operating Name/ MSHA Identification Number	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Total Number of Mining Related Fatalities (#)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Coffin Butte	—	—	—	300	—	—	—	—
Concrete, Inc.	—	—	—	263	—	—	—	—
Crusher #1	—	—	—	200	—	—	—	—
Davis Slough	1	—	—	—	—	—	—	—
Dralle Pit	—	—	—	500	—	—	3	—
Drycreek Landfill	—	—	—	100	—	—	—	—
Elk River Wash Plant	—	—	—	—	—	—	—	1
Eugene	5	—	—	924	—	—	—	—
Fisher Island	—	—	—	1,848	—	—	—	—
Fitzgerald Pit	—	—	—	200	—	—	—	—
Gardner Pit	—	—	—	—	1	—	—	—
Gazley Pit	—	—	—	100	—	—	—	—
Gresham S&G	1	—	—	725	—	2	—	—
Halawa Quarry	2	—	—	6,904	—	—	—	—
Halawa Valley	—	—	—	815	—	3	—	—
Hallwood Plant	2	—	—	1,404	—	2	2	—
Kalispell Wash Plant	2	—	—	—	—	—	—	—
Kirkland	—	—	—	300	—	—	—	—
Klatt Terminal	2	—	—	—	—	—	—	—
Kona Sand Plant	—	—	—	200	—	—	—	—
Lampasas Quarry	—	1	—	112	—	—	—	—
Little Falls	—	—	—	—	—	—	—	2
Lone Pine Portable Plant	—	—	—	—	—	1	—	—
Lone Pine Wash Plant	—	—	—	200	—	—	—	—
McKenzie Pit	1	—	—	—	—	—	—	—
Mobile Crusher #1	—	—	—	—	—	2	—	—
Moses Wash Plant	1	—	—	—	—	—	—	—
Orland Plant	3	—	—	—	—	3	8	5
Paetsch Pit	—	1	—	200	—	5	2	—
Pebbly Beach Quarry	5	—	1	3,399	—	4	4	—
Pioneer	2	—	—	570	—	7	5	—
Portable 1	3	—	—	1,306	—	—	—	—
Portable 2	—	—	—	600	—	—	—	—
Portable Crusher #1	1	—	—	—	—	—	—	—
Puunene Quarry	—	—	—	200	—	1	—	—
Quality Quarry	—	—	—	100	—	—	—	—
Quality Rock	4	—	—	21,840	—	3	—	—
Rittenour Pit	—	—	—	—	—	—	—	3
Rockville 3 Quarry	—	—	—	—	—	1	—	—
Round Prairie	2	—	—	—	—	—	—	—
Salem-Reed Pit	2	—	—	894	—	—	4	4
Sauk Rapids	—	—	—	100	—	—	—	—

Mine or Operating Name/ MSHA Identification Number	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Total Number of Mining Related Fatalities (#)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Sky High Pit	3	—	—	424	—	1	1	—
Slatt Quarry	—	—	—	—	—	2	—	—
Star Pit #1	1	—	—	700	—	5	5	—
Stark Pit	—	—	—	200	—	—	—	—
Stayton	—	—	—	100	—	—	—	—
Sullivan Quarry MC1	2	—	—	200	—	—	—	—
T Olson Pit	—	—	—	—	—	—	—	3
Vernalis	—	—	—	100	—	—	—	—
Voight Pit	—	—	—	200	—	—	—	—
VR Pit	—	—	—	—	—	1	—	—
Waikapu Quarry	3	—	1	1,589	—	—	2	2
Waikapu Sand Pit	—	—	—	100	—	—	—	—
Waimea Quarry	—	—	—	93	—	—	—	—
Wash Plant	—	—	—	—	—	2	—	—
Waterview	1	—	—	1,361	—	—	—	—
Watters Quarry	—	—	—	100	—	—	—	—
Weddle Pit	—	—	—	200	—	—	—	—
Wienmann Pit	—	—	—	2,512	—	—	1	—
Wong Pit (Jig Plant)	2	—	—	—	—	1	—	—
	58	2	2	$ 55,765	1	49	39	25

FIDELITY EXPLORATION & PRODUCTION COMPANY

Estimated

Future Reserves

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2011

/s/ Joseph E. Blankenship

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

[SEAL]

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

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235 TELEPHONE (713) 651-9191

January 10, 2012

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

Gentlemen:

At the request of Fidelity Exploration & Production Company (Fidelity), Ryder Scott Company (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2011 prepared by Fidelity's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Fidelity Exploration & Production Company is an indirect wholly owned subsidiary of MDU Resources (MDU).

Our third party reserves audit, completed on January 9, 2012 and presented herein, was prepared for public disclosure by MDU in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent Fidelity's estimated net reserves attributable to the leasehold and royalty interests in certain properties owned by Fidelity, which were all reviewed by Ryder Scott, as of December 31, 2011. The properties reviewed by Ryder Scott incorporate 4331 reserve determinations and are located in the states of Alabama, Colorado, Louisiana, Montana, North Dakota, New Mexico, Oklahoma, Texas, Utah, Wyoming, and in federal waters offshore Louisiana and Texas.

The properties reviewed by Ryder Scott account for 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Fidelity as of December 31, 2011.

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

Based on our review, including the data, technical processes and interpretations presented by Fidelity, it is our opinion that the overall procedures and methodologies utilized by Fidelity in preparing their estimates of the proved reserves as of December 31, 2011 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Fidelity are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Fidelity has informed us that in the preparation of their reserve and income projections, as of December 31, 2011, they used average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Fidelity attributable to Fidelity's interests in properties that we reviewed are summarized as follows:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold and Royalty Interests of
Fidelity Exploration & Production Company

As of December 31, 2011

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Total Net Reserves				
All Audited by Ryder Scott				
Oil/Condensate - Barrels	22,792,968	860,790	3,351,683	27,005,441
Plant Products - Barrels	3,815,421	1,408,838	2,117,263	7,341,522
Gas - MMCF	274,534	28,961	76,332	379,827

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

Reserves Included in This Report

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

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

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

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

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

Audit Data, Methodology, Procedure and Assumptions

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

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

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

The proved reserves for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 95 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation, which utilized extrapolations of historical production and pressure data available through August, 2011, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Fidelity or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 5 percent of the proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

Approximately 100 percent of the proved developed non-producing and undeveloped reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Fidelity for our review or which we have obtained from public data sources that were available through August, 2011. The data utilized from the analogues as well as well and seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

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

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

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves

reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Fidelity relating to hydrocarbon prices and costs as noted herein.

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

The initial SEC hydrocarbon prices in effect on December 31, 2011 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by Fidelity for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

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

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

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$96.19/Bbl	$90.82/Bbl
	NGLs	WTI Cushing	$96.19/Bbl	$55.24/Bbl
	Gas	Colorado Interstate	$3.93/MMBTU	$3.50/MCF

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

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

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

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

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Fidelity's plans to develop these reserves as of December 31, 2011. The implementation of Fidelity's development plans as presented to us is subject to the approval process adopted by Fidelity's management. As the result of our inquires during the course of our review, Fidelity has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Fidelity's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Fidelity. Additionally, Fidelity has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans. All of Fidelity's proved undeveloped reserves are scheduled to be developed within the five year window, from the first booked date, as prescribed by the SEC.

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

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

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

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

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

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

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

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

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Fidelity, it is our opinion that the overall procedures and methodologies utilized by Fidelity in preparing their estimates of the proved reserves as of December 31, 2011 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Fidelity are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

We were in reasonable agreement with Fidelity's estimates of proved reserves for the properties which we reviewed. As a consequence, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by Fidelity.

Standards of Independence and Professional Qualification

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

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

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

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

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

Terms of Usage

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

MDU makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, MDU has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of MDU of the references to our name as well as to the references to our third party report for Fidelity, which appears in the December 31, 2011 annual report on Form 10-K of MDU. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by MDU.

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

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

Very truly yours,

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

/s/ Joseph E. Blankenship

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

[SEAL]

JEB/pl

Professional Qualifications of Primary Technical Person

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

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

Mr. Blankenship earned a Bachelor of Science degree in Mechanical Engineering from the University of Alabama in 1977. He is a member of the Honorary Engineering Society Pi Tau Sigma and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers (SPE) and the Society of Petroleum Evaluation Engineers (SPEE). He has served as Chairman of the SPE Newsletter Committee and has been invited by the SPEE to lecture on the subject of Coal Seam evaluation.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Blankenship fulfills. Mr. Blankenship's continuing education in 2011 included classes on professional resource planning, Microsoft Access utilization in the area of reserves evaluation, Fekete Reservoir Engineering Software optimization and utilization, and the utilization of correct SEC Reserves and PRMS Resource evaluation criteria.

In 2010, Mr. Blankenship presented 1 hour of formalized training to the professional staff at Ryder Scott. Mr. Blankenship attended Ryder Scott's 2010 Reserves Conference, which included a presentation by Dr. John Lee, on the new SEC regulations relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register; and Mr. Blankenship also attended a class on Deep Water Gulf of Mexico reserves evaluation.

In 2009, Mr. Blankenship attended 41 hours of formalized training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS), reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants. Mr. Blankenship was class instructor in Ryder Scott's 2009 and 2010 in-house courses on unconventional reserves evaluation.

Based on his educational background, professional training and more than 34 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Blankenship has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

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

PREAMBLE

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

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

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

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

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

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

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

RESERVES (SEC DEFINITIONS)

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

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

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

PROVED RESERVES (SEC DEFINITIONS)

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

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

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

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

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

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

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

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

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

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

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

Probable reserves. *Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.*

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion.
Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

RESERVES STATUS DEFINITIONS AND GUIDELINES

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

and

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

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

DEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

Developed Producing (SPE-PRMS Definitions)

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

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

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

<u>Developed Non-Producing</u>
Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

<u>Shut-In</u>
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals which are open at the time of the estimate, but which have not started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

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

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

<u>UNDEVELOPED RESERVES (SEC DEFINITIONS)</u>

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

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

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

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

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

Income Taxes (Tables)

12 Months Ended Dec. 31, 2011

Income Tax Disclosure [Abstract]

Components of income (loss) before income taxes

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

	2011	2010	2009
	(In thousands)		
United States	**$ 333,486**	$ 336,450	$(227,021)
Foreign	**2,740**	30,100	7,655
Income (loss) before income taxes from continuing operations	**$ 336,226**	$ 366,550	$(219,366)

Income tax expense (benefit)

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

	2011	2010	2009
	(In thousands)		
Current:			
Federal	**$ (7,188)**	$ 37,014	$ 64,389
State	**778**	10,589	8,284
Foreign	**127**	4,451	254
	(6,283)	52,054	72,927
Deferred:			
Income taxes -			
Federal	**105,528**	62,618	(147,607)
State	**13,157**	4,147	(22,370)
Investment tax credit - net	**240**	(180)	213
	118,925	66,585	(169,764)
Change in uncertain tax benefits	**(1,048)**	3,230	562
Change in accrued interest	**(1,320)**	661	183
Total income tax expense (benefit)	**$ 110,274**	$ 122,530	$ (96,092)

Deferred tax assets and deferred tax liabilities

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

	2011	2010
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 119,189**	$ 114,427
Accrued pension costs	**95,260**	82,085
Asset retirement obligations	**26,380**	24,391
Legal and environmental contingencies	**21,788**	13,622
Compensation-related	**16,241**	17,261
Other	**41,055**	40,307
Total deferred tax assets	**319,913**	292,093
Deferred tax liabilities:		

Depreciation and basis differences on property, plant and equipment	**715,482**	679,809
Basis differences on natural gas and oil producing properties	**210,146**	152,455
Regulatory matters	**84,963**	64,017
Intangible asset amortization	**14,307**	14,843
Other	**23,774**	20,348
Total deferred tax liabilities	**1,048,672**	931,472
Net deferred income tax liability	**$ (728,759)**	$(639,379)

[Schedule of Change in Net Deferred Income Tax Liability Reconciliation [Table Text Block]]

The following table reconciles the change in the net deferred income tax liability from December 31, 2010, to December 31, 2011, to deferred income tax expense:

	2011
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 89,380**
Deferred taxes associated with other comprehensive loss	**9,678**
Deferred taxes associated with discontinued operations	**8,090**
Other	**11,777**
Deferred income tax expense for the period	**$ 118,925**

[Reconciliation of income tax expense (benefit) at statutory federal rate versus actual rate]

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,	**2011**		2010		2009	
	Amount	%	Amount	%	Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	**$117,679**	**35.0**	$128,293	35.0	$(76,778)	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	**10,653**	**3.2**	10,210	2.8	(7,280)	3.3
Resolution of tax matters and uncertain tax positions	**(3,906)**	**(1.2)**	667	.2	881	(.4)
Federal renewable energy credit	**(3,485)**	**(1.0)**	(2,185)	(.6)	(1,452)	.7
Depletion allowance	**(3,266)**	**(1.0)**	(2,810)	(.8)	(2,320)	1.0
Deductible K-Plan dividends	**(2,282)**	**(.7)**	(2,309)	(.6)	(2,369)	1.1

Foreign operations	**(391)**	**(.1)**	(588)	(.2)	(1,148)	.5
Domestic production activities deduction	**—**	**—**	—	—	(856)	.4
Other	**(4,728)**	**(1.4)**	(8,748)	(2.4)	(4,770)	2.2
Total income tax expense (benefit)	**$110,274**	**32.8**	$122,530	33.4	$(96,092)	43.8

Reconciliation of unrecognized tax benefits (excluding interest)

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

	2011	2010	2009
	(In thousands)		
Balance at beginning of year	**$ 9,378**	$ 6,148	$ 5,586
Additions for tax positions of prior years	**4,172**	3,230	562
Settlements	**(2,344)**	—	—
Balance at end of year	**$ 11,206**	$ 9,378	$ 6,148

Equity Method Investments (Details) (USD $) In Millions, unless otherwise specified	3 Months Ended		12 Months Ended							
	Dec. 31, 2010	Dec. 31, 2011	Dec. 31, 2011 Brazilian Transmission Lines [Member]	Dec. 31, 2010 Brazilian Transmission Lines [Member]	Nov. 30, 2011 Brazilian Transmission Lines [Member]	Nov. 30, 2010 Brazilian Transmission Lines [Member]	Dec. 31, 2009 Brazilian Transmission Lines [Member]	Nov. 30, 2010 ECTE [Member]	Nov. 30, 2011 ENTE [Member]	Nov. 30, 2011 ERTE [Member]
Schedule of Equity Method Investments [Line Items]										
Recognized gain on sale of ownership interests			$ 1.0	$ 22.7						
Recognized gain on sale of ownership interests, after tax	13.8		0.6	13.8						
Percentage Ownership Interest in Equity Method Investment Sold								59.96%	100.00%	100.00%
Remaining Interest					0.25					
Number of separate parties with which company entered into agreements to sell equity ownership interests							3			
Number of years over which remaining ownership interest in equity method investment will be sold						4 years				
Total assets of equity method investments	107.4	111.1								
Total long-term debt of equity method investments	30.1	37.1								
Investment in equity method investments	10.9	9.2								
Undistributed earnings of equity method investments	$ 1.9	$ 3.7								

Summary of Significant Accounting Policies (Details 5) (USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011	Dec. 31, 2010
Revenue recognition [Abstract]		
Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain	$ 80.2	$ 87.3
Percentage-of-completion method [Abstract]		
Costs and estimated earnings in excess of billings on uncompleted contracts	54.3	46.6
Billings in excess of costs and estimated earnings on uncompleted contracts	79.1	65.2
Amounts representing balances billed but not paid by customers under retainage provisions in contracts	51.5	51.1
Amounts of receivable retainage expected to be paid within one year or less	49.3	50.4
Long-term receivable retainage	2.2	0.7
Derivative instruments [Abstract]		
Maximum period allowed to hedge monthly forecasted sales of natural gas and oil production at Fidelity (in months)	36 months	
Maximum period allowed to hedge interest rate derivative instruments (in months)	24 months	
Maximum period allowed to hedge foreign currency derivative instruments (in months)	12-month period	
Maximum period allowed to hedge monthly forecasted purchases of natural gas at Cascade and Intermountain (in years)	three years	
Maximum period for settlement of all interest rate derivative transactions (in days)	90 days	
Maximum period for settlement of foreign currency derivative transaction (in months)	12-month period	
Natural gas costs recoverable or refundable through rate adjustments [Abstract]		
Minimum period over which natural gas costs greater or less than amounts being recovered become recoverable or refundable through rate adjustments (in months)	12	
Maximum period over which natural gas costs greater or less than amounts being recovered become recoverable or refundable through rate adjustments (in months)	28 months	
Natural gas costs refundable through rate adjustments	45.1	37.0
Natural gas costs recoverable through rate adjustments	2.6	6.6
Insurance [Abstract]		
Maximum amount of deductibles for workers' compensation insurance per occurrence	1	
Maximum amount of deductibles for automobile liability and general liability insurance per accident or occurrence	$ 1	
Income taxes [Abstract]		
Threshold of likelihood of tax benefits being realized upon ultimate settlement with a taxing authority (in hundredths)	50.00%	

Income Taxes (Details 2) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Current [Abstract]			
Federal	$ (7,188)	$ 37,014	$ 64,389
State	778	10,589	8,284
Foreign	127	4,451	254
Total Current Income Taxes	(6,283)	52,054	72,927
Deferred [Abstract]			
Federal	105,528	62,618	(147,607)
State	13,157	4,147	(22,370)
Investment tax credit - net	240	(180)	213
Total Deferred Income Taxes	118,925	66,585	(169,764)
Change in uncertain tax benefits	(1,048)	3,230	562
Change in accrued interest	(1,320)	661	183
Income tax expense benefit	$ 110,274	$ 122,530	$ (96,092)

Goodwill and Other Intangible Assets (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended			
	Dec. 31, 2011		Dec. 31, 2010	
Goodwill [Roll Forward]				
Balance as of beginning of period	$ 634,633	[1]	$ 629,463	[1]
Goodwill Acquired During the Year	298	[2]	5,170	[3]
Balance as of end of period	634,931	[1]	634,633	[1]
Electric [Member]				
Goodwill [Roll Forward]				
Balance as of beginning of period	0		0	
Goodwill Acquired During the Year	0	[2]	0	[3]
Balance as of end of period	0		0	
Exploration and production [Member]				
Goodwill [Roll Forward]				
Balance as of beginning of period	0		0	
Goodwill Acquired During the Year	0	[2]	0	[3]
Balance as of end of period	0		0	
Natural gas distribution [Member]				
Goodwill [Roll Forward]				
Balance as of beginning of period	345,736		345,736	
Goodwill Acquired During the Year	0	[2]	0	[3]
Balance as of end of period	345,736		345,736	
Construction services [Member]				
Goodwill [Roll Forward]				
Balance as of beginning of period	102,870		100,127	
Goodwill Acquired During the Year	298	[2]	2,743	[3]
Balance as of end of period	103,168		102,870	
Pipeline and energy services [Member]				
Goodwill [Roll Forward]				
Balance as of beginning of period	9,737	[1]	7,857	[1]
Goodwill Acquired During the Year	0	[2]	1,880	[3]
Balance as of end of period	9,737	[1]	9,737	[1]
Accumulated impairment which occurred in prior periods	12,300		12,300	
Construction materials and contracting [Member]				
Goodwill [Roll Forward]				
Balance as of beginning of period	176,290		175,743	
Goodwill Acquired During the Year	0	[2]	547	[3]
Balance as of end of period	176,290		176,290	
Other [Member]				

Goodwill [Roll Forward]		
Balance as of beginning of period	0	0
Goodwill Acquired During the Year	0 [2]	0 [3]
Balance as of end of period	$ 0	$ 0

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

[2] Includes a purchase price adjustment that was not material related to an acquisition in a prior period.

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

Fair Value of Plan Assets (Details) (USD $) In Thousands, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2011 Other Postretirement Benefit Plans, Defined Benefit [Member]	Dec. 31, 2010 Other Postretirement Benefit Plans, Defined Benefit [Member]	Dec. 31, 2009 Other Postretirement Benefit Plans, Defined Benefit [Member]	Dec. 31, 2011 Pension Plans, Defined Benefit [Member]	Dec. 31, 2010 Pension Plans, Defined Benefit [Member]	Dec. 31, 2009 Pension Plans, Defined Benefit [Member]	Dec. 31, 2011 Cash and Cash Equivalents [Member] Other Postretirement Benefit Plans, Defined Benefit [Member]	Dec. 31, 2010 Cash and Cash Equivalents [Member] Other Postretirement Benefit Plans, Defined Benefit [Member]	Dec. 31, 2011 Cash and Cash Equivalents [Member] Pension Plans, Defined Benefit [Member]
Defined Benefit Plan Disclosure [Line Items]											
Number of Investment Managers of the Plan Assets			1			12					
Defined Benefit Plan Fair Value Of Plan Assets Before Obligations For Collateral Received							$ 303,292				
Defined Benefit Plan Fair Value Of Plan Assets Obligations For Collateral Received							29,698				
Defined Benefit Plan, Fair Value of Plan Assets			68,003	70,610	66,984	278,000	277,998	238,327	1,893	1,327	19,790
Percentage investment in common stock of small-cap companies	34.00%	35.00%					6.00%				
Percentage investment in common stock of mid-cap companies	35.00%	35.00%				26.00%	28.00%				
Percentage investment in common stock of large-cap companies	32.00%	31.00%	49.00%	55.00%		26.00%	24.00%				
Percentage investment in US Treasuries			15.00%			15.00%	15.00%				
Percentage investment in mortgage-backed securities			12.00%	12.00%			11.00%				
Percentage investment in corporate bonds			11.00%	21.00%		6.00%	10.00%				
Percentage investment in foreign fixed income investments							8.00%				
Percentage investment in other investments			13.00%	14.00%		29.00%					
Change in net plan assets [Roll Forward]											
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset Value, Beginning Balance											
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset, Gain (Loss) Included in Earnings											
Defined Benefit Plan, Purchases, Sales, and Settlements											
Fair Value, Measurement with Unobservable Inputs Reconciliation, Recurring Basis, Asset Value, Ending Balance											

[1] (a) Collective and mutual funds invest approximately 28 percent in common stock of mid-cap U.S. companies, 24 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 11 percent in mortgage-backed securities, 10 percent in corporate bonds, 8 percent in foreign fixed income investments and 6 percent in common stock of small-cap U.S. companies.

[2] (b) This class includes collateral held at December 31, 2010, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, mutual funds and commercial paper.

[3] The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.

[4] The insurance investment contract invests approximately 55 percent in common stock of large-cap U.S. companies, 21 percent in corporate bonds, 12 percent in mortgage-backed securities and 14 percent in other investments.

[5] a) Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.

Summary of Significant Accounting Policies (Details 3) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Property, Plant and Equipment [Line Items]			
Allowance for Funds Used During Construction, Capitalized Cost of Equity and Interest	$ 15,100,000	$ 17,600,000	$ 17,400,000
Property, plant and equipment	7,646,222,000	7,218,503,000	
Less accumulated depreciation, depletion and amortization	3,361,208,000	3,103,323,000	2,872,465,000
Net property, plant and equipment	4,285,014,000	4,115,180,000	3,894,117,000
Mcf equivalent average rate for amortization under units-of-production method (in dollars per Mcf)	2.04	1.77	1.64
Capitalized Costs of Unproved Properties Excluded from Amortization, Cumulative	232,462,000	182,402,000	178,214,000
Electric [Member]			
Property, Plant and Equipment [Line Items]			
Property, plant and equipment	1,068,524,000 [1]	1,027,034,000 [1]	941,791,000 [1]
Natural gas distribution [Member]			
Property, Plant and Equipment [Line Items]			
Property, plant and equipment	1,568,866,000 [1]	1,508,845,000 [1]	1,456,208,000 [1]
Pipeline and energy services [Member]			
Property, Plant and Equipment [Line Items]			
Property, plant and equipment	719,291,000	683,807,000	675,199,000
Exploration and production [Member]			
Property, Plant and Equipment [Line Items]			
Property, plant and equipment	2,615,146,000	2,356,938,000	2,028,794,000
Construction materials and contracting [Member]			
Property, Plant and Equipment [Line Items]			
Property, plant and equipment	1,499,852,000	1,486,375,000	1,514,989,000
Construction services [Member]			
Property, Plant and Equipment [Line Items]			
Property, plant and equipment	124,796,000	122,940,000	116,236,000
All Other Segments [Member]			
Property, Plant and Equipment [Line Items]			
Property, plant and equipment	49,747,000	32,564,000	33,365,000
Regulated Operation [Member] | Electric [Member] | Electric Generation Equipment [Member]			
Property, Plant and Equipment [Line Items]			
Property, plant and equipment	546,783,000	538,071,000	
Weighted Average Depreciable Life in Years	47		
Regulated Operation [Member] | Electric [Member] | Electric Distribution [Member]			
Property, Plant and Equipment [Line Items]			
Property, plant and equipment	255,232,000	243,205,000	
Weighted Average Depreciable Life in Years	36		

Regulated Operation [Member] | Electric [Member] | Electric Transmission [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	179,580,000	161,972,000
Weighted Average Depreciable Life in Years	44	
Regulated Operation [Member] | Electric [Member] | Other Capitalized Property Plant and Equipment [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	86,929,000	83,786,000
Weighted Average Depreciable Life in Years	13	
Regulated Operation [Member] | Natural gas distribution [Member] | Distribution [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	1,257,360,000	1,223,239,000
Weighted Average Depreciable Life in Years	38	
Regulated Operation [Member] | Natural gas distribution [Member] | Other Capitalized Property Plant and Equipment [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	311,506,000	285,606,000
Weighted Average Depreciable Life in Years	23	
Regulated Operation [Member] | Pipeline and energy services [Member] | Transmission [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	386,227,000	357,395,000
Weighted Average Depreciable Life in Years	52	
Regulated Operation [Member] | Pipeline and energy services [Member] | Gathering [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	42,378,000	41,931,000
Weighted Average Depreciable Life in Years	19	
Regulated Operation [Member] | Pipeline and energy services [Member] | Storage [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	41,908,000	33,967,000
Weighted Average Depreciable Life in Years	51	
Regulated Operation [Member] | Pipeline and energy services [Member] | Other Capitalized Property Plant and Equipment [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	36,179,000	33,938,000
Weighted Average Depreciable Life in Years	29	
Unregulated Operation [Member] | Pipeline and energy services [Member] | Gathering [Member]		
Property, Plant and Equipment [Line Items]		

Property, plant and equipment	198,864,000	203,064,000
Weighted Average Depreciable Life in Years	17	
Unregulated Operation [Member] | Pipeline and energy services [Member] | Other Capitalized Property Plant and Equipment [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	13,735,000	13,512,000
Weighted Average Depreciable Life in Years	10	
Unregulated Operation [Member] | Exploration and production [Member] | Oil and natural gas properties [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	2,577,576,000 [2]	2,320,967,000 [2]
Unregulated Operation [Member] | Exploration and production [Member] | Other Capitalized Property Plant and Equipment [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	37,570,000	35,971,000
Weighted Average Depreciable Life in Years	9	
Unregulated Operation [Member] | Construction materials and contracting [Member] | Land [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	126,790,000	124,018,000
Unregulated Operation [Member] | Construction materials and contracting [Member] | Building and Building Improvements [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	67,627,000	65,003,000
Weighted Average Depreciable Life in Years	20	
Unregulated Operation [Member] | Construction materials and contracting [Member] | Machinery, vehicles and equipment [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	902,136,000	899,365,000
Weighted Average Depreciable Life in Years	12	
Unregulated Operation [Member] | Construction materials and contracting [Member] | Construction in Progress [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	8,085,000	4,879,000
Unregulated Operation [Member] | Construction materials and contracting [Member] | Aggregate reserves [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	395,214,000 [3]	393,110,000 [3]

Unregulated Operation [Member] | Construction services [Member] | Land [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	4,706,000	4,526,000
Unregulated Operation [Member] | Construction services [Member] | Building and Building Improvements [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	15,001,000	14,101,000
Weighted Average Depreciable Life in Years	22	
Unregulated Operation [Member] | Construction services [Member] | Machinery, vehicles and equipment [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	95,891,000	94,252,000
Weighted Average Depreciable Life in Years	7	
Unregulated Operation [Member] | Construction services [Member] | Other Capitalized Property Plant and Equipment [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	9,198,000	10,061,000
Weighted Average Depreciable Life in Years	4	
Unregulated Operation [Member] | All Other Segments [Member] | Land [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	2,837,000	2,837,000
Unregulated Operation [Member] | All Other Segments [Member] | Other Capitalized Property Plant and Equipment [Member]		
Property, Plant and Equipment [Line Items]		
Property, plant and equipment	$ 46,910,000	$ 29,727,000
Weighted Average Depreciable Life in Years	24	

[1] Includes allocations of common utility property.

[2] Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $2.04, $1.77 and $1.64 for the years ended December 31, 2011, 2010 and 2009, respectively. Includes natural gas and oil properties accounted for under the full-cost method, of which $232.5 and $182.4 million were excluded from amortization at December 31, 2011 and 2010, respectively.

[3] Depleted on the units-of-production method.

Derivative Instruments (Tables)	12 Months Ended Dec. 31, 2011
Derivative Instruments and Hedging Activities Disclosure [Abstract]	
Derivative Instruments (Tables)	The location and fair value of the Company's derivative instruments on the Consolidated Balance Sheets were as follows:

Asset Derivatives	Location on Consolidated Balance Sheets		Fair Value at December 31, 2011		Fair Value at December 31, 2010
			(In thousands)		
Designated as hedges:					
Commodity derivatives	Commodity derivative instruments	$	27,687	$	15,123
	Other assets - noncurrent		2,768		4,104
			30,455		19,227
Not designated as hedges:					
Commodity derivatives	Commodity derivative instruments		—		—
	Other assets - noncurrent		—		—
			—		—
Total asset derivatives		$	30,455	$	19,227

Liability Derivatives	Location on Consolidated Balance Sheets		Fair Value at December 31, 2011		Fair Value at December 31, 2010
			(In thousands)		
Designated as hedges:					
Commodity derivatives	Commodity derivative instruments	$	12,727	$	15,069
	Other liabilities - noncurrent		937		6,483
Interest rate derivatives	Other accrued liabilities		827		—
	Other liabilities - noncurrent		3,935		—
			18,426		21,552
Not designated as hedges:					
Commodity derivatives	Commodity derivative instruments		437		9,359
	Other liabilities - noncurrent		—		—
			437		9,359

Total liability derivatives	$	18,863	$	30,911

Future Contributions, Benefit Payments and Subsidies (Details) (USD $)	Dec. 31, 2011
Pension Plans, Defined Benefit [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Defined Benefit Plan, Estimated Future Employer Contributions in Next Fiscal Year	$ 20,200,000
Defined Benefit Plan, Expected Future Benefit Payments in Year One	22,426,000
Defined Benefit Plan, Expected Future Benefit Payments in Year Two	22,811,000
Defined Benefit Plan, Expected Future Benefit Payments in Year Three	23,082,000
Defined Benefit Plan, Expected Future Benefit Payments in Year Four	23,508,000
Defined Benefit Plan, Expected Future Benefit Payments in Year Five	23,893,000
Defined Benefit Plan, Expected Future Benefit Payments in Five Fiscal Years Thereafter	127,895,000
Other Postretirement Benefit Plans, Defined Benefit [Member]	
Defined Benefit Plan Disclosure [Line Items]	
Defined Benefit Plan, Estimated Future Employer Contributions in Next Fiscal Year	4,000,000
Defined Benefit Plan, Expected Future Benefit Payments in Year One	6,892,000
Defined Benefit Plan, Expected Future Benefit Payments in Year Two	7,062,000
Defined Benefit Plan, Expected Future Benefit Payments in Year Three	7,188,000
Defined Benefit Plan, Expected Future Benefit Payments in Year Four	7,298,000
Defined Benefit Plan, Expected Future Benefit Payments in Year Five	7,371,000
Defined Benefit Plan, Expected Future Benefit Payments in Five Fiscal Years Thereafter	37,682,000
Prescription Drug Subsidy Receipts, Year One	618,000
Prescription Drug Subsidy Receipts, Year Two	656,000
Prescription Drug Subsidy Receipts, Year Three	694,000
Prescription Drug Subsidy Receipts, Year Four	730,000
Prescription Drug Subsidy Receipts, Year Five	766,000
Prescription Drug Subsidy Receipts, Five Fiscal Years Thereafter	$ 4,322,000

Income Taxes (Details 5) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Undistributed earnings from foreign operations	$ 6,900,000		
Deferred Tax Liabilities, Undistributed Foreign Earnings	1,600,000		
Computed tax at federal statutory rate	117,679,000	128,293,000	(76,778,000)
Federal statutory rate (in hundredths)	35.00%	35.00%	35.00%
Increases (reductions) resulting from [Abstract]			
State income taxes, net of federal income tax benefit (expense)	10,653,000	10,210,000	(7,280,000)
State income tax rate (in hundredths)	3.20%	2.80%	3.30%
Resolution of tax matters and uncertain tax positions	(3,906,000)	667,000	881,000
Resolution of tax matters and uncertain tax positions rate (in hundredths)	(1.20%)	0.20%	(0.40%)
Income tax reconciliation, tax credits, other	(3,485,000)	(2,185,000)	(1,452,000)
Effective income tax rate reduction, tax credits, other	(1.00%)	(0.60%)	0.70%
Depletion allowance	(3,266,000)	(2,810,000)	(2,320,000)
Depletion allowance rate (in hundredths)	(1.00%)	(0.80%)	1.00%
Deductible K-Plan dividends	(2,282,000)	(2,309,000)	(2,369,000)
Deductible K-Plan dividends rate (in hundredths)	(0.70%)	(0.60%)	1.10%
Foreign operations	(391,000)	(588,000)	(1,148,000)
Foreign operations rate (in hundredths)	(0.10%)	(0.20%)	0.50%
Domestic production activities deduction	0	0	(856,000)
Domestic production activities deduction rate (in hundredths)	0.00%	0.00%	0.40%
Other	(4,728,000)	(8,748,000)	(4,770,000)
Other rate (in hundredths)	(1.40%)	(2.40%)	2.20%
Total income tax expense (benefit)	$ 110,274,000	$ 122,530,000	$ (96,092,000)
Total income tax expense (benefit) rate (in hundredths)	32.80%	33.40%	43.80%

Commitments and Contingencies (Details 4) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Unrecorded Unconditional Purchase Obligation [Line Items]			
Term of Unrecorded Unconditional Purchase Obligation	one to 49 years		
Purchase commitments due			
2012	$ 478,000,000		
2013	215,900,000		
2014	135,800,000		
2015	71,100,000		
2016	36,700,000		
Thereafter	287,000,000		
Unrecorded Unconditional Purchase Obligation, Purchases	$ 626,300,000	$ 611,700,000	$ 723,100,000

Regulatory Assets and Liabilities (Details) (USD $)	Dec. 31, 2011		Dec. 31, 2010	
Regulatory Assets and Liabilities				
Regulatory Assets	$ 359,009,000		$ 316,241,000	
Regulatory Liabilities	460,229,000		413,097,000	
Net Regulatory position	(101,220,000)		(96,856,000)	
Regulatory assets not earning a rate of return	216,400,000			
Plant removal and decommissioning costs [Member]				
Regulatory Assets and Liabilities				
Regulatory Liabilities	289,972,000	[1]	276,652,000	[1]
Deferred income taxes liability [Member]				
Regulatory Assets and Liabilities				
Regulatory Liabilities	84,963,000	[2]	64,017,000	[2]
Liabilities Refundable Gas Costs [Member]				
Regulatory Assets and Liabilities				
Regulatory Liabilities	45,064,000	[3]	36,996,000	[3]
Taxes refundable to customers [Member]				
Regulatory Assets and Liabilities				
Regulatory Liabilities	31,837,000	[1]	19,352,000	[1]
Other regulatory liabilities [Member]				
Regulatory Assets and Liabilities				
Regulatory Liabilities	8,393,000	[1],[3]	16,080,000	[1],[3]
Pension and postretirement benefits [Member]				
Regulatory Assets and Liabilities				
Regulatory Assets	171,492,000	[4],[5]	103,818,000	[4],[5]
Deferred income taxes asset [Member]				
Regulatory Assets and Liabilities				
Regulatory Assets	119,189,000	[2]	114,427,000	[2]
Deferred Income Tax Charges [Member]				
Regulatory Assets and Liabilities				
Regulatory Assets	12,433,000	[4]	11,961,000	[4]
Plant costs [Member]				
Regulatory Assets and Liabilities				
Estimated Recovery Period	Over plant lives	[6]		
Regulatory Assets	10,256,000	[4]	9,964,000	[4]
Long-term debt refinancing costs [Member]				
Regulatory Assets and Liabilities				
Estimated Recovery Period	Up to 27 years	[6]		
Regulatory Assets	10,112,000	[4]	11,101,000	[4]
Costs related to identifying generation development [Member]				
Regulatory Assets and Liabilities				

Estimated Recovery Period	Up to 15 years	[6]		
Regulatory Assets	9,817,000	[4]	13,777,000	[4]
Natural gas supply derivatives [Member]				
Regulatory Assets and Liabilities				
Estimated Recovery Period	Up to 1 year	[6]		
Regulatory Assets	437,000	[7]	9,359,000	[7]
Natural gas cost recoverable through rate adjustments [Member]				
Regulatory Assets and Liabilities				
Estimated Recovery Period	Up to 28 months	[6]		
Regulatory Assets	2,622,000	[7]	6,609,000	[7]
Other regulatory assets [Member]				
Regulatory Assets and Liabilities				
Estimated Recovery Period	Largely within 1 year	[6]		
Regulatory Assets	$ 22,651,000	[4],[7]	$ 35,225,000	[4],[7]

[1] Included in other liabilities on the Consolidated Balance Sheets.
[2] Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.
[3] Included in other accrued liabilities on the Consolidated Balance Sheets.
[4] Included in deferred charges and other assets on the Consolidated Balance Sheets.
[5] Recovered as expense is incurred.
[6] Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
[7] Included in prepayments and other current assets on the Consolidated Balance Sheets.

Benefit Obligations and Plan Assets (Details) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Pension Plans, Defined Benefit [Member]			
Defined Benefit Plan, Change in Benefit Obligation [Roll Forward]			
Defined Benefit Plan, Benefit Obligation	$ 388,589,000	$ 352,915,000	
Service cost	2,252,000	2,889,000	8,127,000
Interest cost	19,500,000	19,761,000	21,919,000
Plan Participants' contributions	0	0	
Amendments	0	353,000	
Actuarial loss	62,722,000	34,687,000	
Curtailment gain	(13,939,000)	0	
Benefits Paid	(23,506,000)	(22,016,000)	
Defined Benefit Plan, Benefit Obligation	435,618,000	388,589,000	352,915,000
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]			
Fair value of plan assets at beginning of year	277,598,000	255,327,000	
Actual gain (loss) on plan assets	(4,718,000)	37,853,000	
Employer contribution	28,626,000	6,434,000	
Plan Participants' contributions	0	0	
Benefits Paid	(23,506,000)	(22,016,000)	
Defined Benefit Plan, Fair Value of Plan Assets	278,000,000	277,598,000	255,327,000
Funded status - under	(157,618,000)	(110,991,000)	
Defined Benefit Plan, Amounts Recognized in Balance Sheet [Abstract]			
Other accrued Liabilities (current)	0	0	
Other liabilities (noncurrent)	(157,618,000)	(110,991,000)	
Net amount recognized	(157,618,000)	(110,991,000)	
Actuarial loss	189,494,000	117,840,000	
Prior service cost (credit)	(632,000)	631,000	
Transition obligation	0	0	
Total	188,862,000	118,471,000	
Defined Benefit Plan, Accumulated Benefit Obligation	435,600,000	374,500,000	
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets, Aggregate Projected Benefit Obligation	435,618,000	388,589,000	
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets, Aggregate Accumulated Benefit Obligation	435,618,000	374,538,000	
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets, Aggregate Fair Value of Plan Assets	278,000,000	277,598,000	
Other Postretirement Benefit Plans, Defined Benefit [Member]			

Defined Benefit Plan, Change in Benefit Obligation [Roll Forward]			
Defined Benefit Plan, Benefit Obligation	91,286,000	88,151,000	
Service cost	1,443,000	1,357,000	2,206,000
Interest cost	4,700,000	4,817,000	5,465,000
Plan Participants' contributions	2,644,000	2,500,000	
Amendments	0	121,000	
Actuarial loss	17,940,000	3,228,000	
Curtailment gain	0	0	
Benefits Paid	(7,324,000)	(8,888,000)	
Defined Benefit Plan, Benefit Obligation	110,689,000	91,286,000	88,151,000
Defined Benefit Plan, Change in Fair Value of Plan Assets [Roll Forward]			
Fair value of plan assets at beginning of year	70,610,000	66,984,000	
Actual gain (loss) on plan assets	(872,000)	7,278,000	
Employer contribution	3,027,000	2,736,000	
Plan Participants' contributions	2,644,000	2,500,000	
Benefits Paid	(7,324,000)	(8,888,000)	
Defined Benefit Plan, Fair Value of Plan Assets	68,085,000	70,610,000	66,984,000
Funded status - under	(42,604,000)	(20,676,000)	
Defined Benefit Plan, Amounts Recognized in Balance Sheet [Abstract]			
Other accrued Liabilities (current)	(550,000)	(525,000)	
Other liabilities (noncurrent)	(42,054,000)	(20,151,000)	
Net amount recognized	(42,604,000)	(20,676,000)	
Actuarial loss	43,861,000	20,751,000	
Prior service cost (credit)	(8,615,000)	(11,292,000)	
Transition obligation	2,128,000	4,253,000	
Total	$ 37,374,000	$ 13,712,000	

Commitments and Contingencies (Details) (USD $)	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2011 Pending or Threatened Litigation [Member] Litigation related to construction materials [Member]	Aug. 31, 2011 Pending or Threatened Litigation [Member] Litigation related to construction materials [Member]	Jan. 18, 2011 Pending or Threatened Litigation [Member] Litigation related to construction materials [Member]	Dec. 31, 2011 Pending or Threatened Litigation [Member] Natural gas gathering operations [Member]	Apr. 20, 2011 Pending or Threatened Litigation [Member] Natural gas gathering operations [Member]	Oct. 31, 2010 Pending or Threatened Litigation [Member] Natural gas gathering operations [Member]	Sep. 30, 2010 Pending or Threatened Litigation [Member] Natural gas gathering operations [Member]	Jan. 13, 2012 Pending or Threatened Litigation [Member] Guarantee obligation under construction contract [Member]	Sep. 19, 2011 Pending or Threatened Litigation [Member] Guarantee obligation under construction contract [Member]	Dec. 31, 2009 Pending or Threatened Litigation [Member] Guarantee obligation under construction contract [Member]	Jul. 31, 2007 Pending or Threatened Litigation [Member] Guarantee obligation under construction contract [Member]
Loss Contingencies [Line Items]													
Potential liabilities related to litigation and environmental matters	$ 64,100,000	$ 45,300,000						$ 26,600,000					
Bicent's bank letter of credit guaranteeing CEM's obligation													10,000,000
Amount of compensatory damages in LPP's notice of demand												149,700,000	
Estimated damages in pending litigation, low estimate					6,000,000	18,800,000							
Estimated damages in pending litigation, high estimate					11,000,000	22,600,000							
Amount Of Damages Dismissed In Pending Litigation			5,000,000										
Estimated Damages Including Interest In Amended Complaint			21,900,000										
Loss Contingency, Estimate of Possible Loss				3,700,000									
Additional Amount Per Day of Potential Penalties				5,000									
Amount of natural gas gathering contract dispute charged to operation and maintenance expense, after tax									16,500,000				
Amount of natural gas gathering contract dispute charged to operations and maintenance, before tax									26,600,000				
Amount Of Counterclaim											14,000,000		
Arbitration Award										22,000,000			
Legal Fees And Expenses Awarded In Litigation							$ 293,000						

Defined Contributions Plans (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Defined Benefit Plan Disclosure [Line Items]			
Defined Contribution Plan, Cost Recognized	$ 27.1	$ 24.4	$ 20.5

Commitments and Contingencies (Details 2) (USD $)	12 Months Ended Dec. 31, 2011
Environmental Litigation Number 1 [Member]	
Site Contingency [Line Items]	
Site Contingency, Loss Exposure, Low Estimate	$ 500,000
Site Contingency, Loss Exposure, High Estimate	11,000,000
Accrual for Environmental Loss Contingencies	1,200,000
Estimated Proportional Share Of Cleanup Liability	50.00%
Environmental Litigation Number 2 [Member]	
Site Contingency [Line Items]	
Site Contingency, Loss Exposure, Low Estimate	340,000
Site Contingency, Loss Exposure, High Estimate	6,400,000
Accrual for Environmental Loss Contingencies	6,400,000
Environmental Litigation Number 3 [Member]	
Site Contingency [Line Items]	
Site Contingency, Loss Exposure Not Accrued, Best Estimate	8,000,000
Portland Harbor Site [Member]	
Site Contingency [Line Items]	
Estimated investigative costs (in excess of)	$ 70,000,000

Benefit Costs and Assumptions (Details) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Pension Plans, Defined Benefit [Member]			
Defined Benefit Plan, Net Periodic Benefit Cost [Abstract]			
Service cost	$ 2,252,000	$ 2,889,000	$ 8,127,000
Interest cost	19,500,000	19,761,000	21,919,000
Expected return on assets	(22,809,000)	(23,643,000)	(25,062,000)
Amortization of prior service cost (credit)	45,000	152,000	605,000
Recognized net actuarial loss	4,656,000	2,622,000	2,096,000
Curtailment loss	1,218,000	0	1,650,000
Amortization of net transition obligation	0	0	0
Net periodic benefit cost, including amount capitalized	4,862,000	1,781,000	9,335,000
Less amount capitalized	1,196,000	791,000	1,127,000
Net periodic benefit cost	3,666,000	990,000	8,208,000
Defined Benefit Plan, Amounts Recognized in Other Comprehensive Income (Loss) [Abstract]			
Net (gain) loss	76,310,000	20,477,000	(29,000,000)
Prior service cost (credit)	0	353,000	0
Amortization of actuarial loss	(4,656,000)	(2,622,000)	(2,096,000)
Amortization of prior service (cost) credit	(1,263,000)	(152,000)	(2,255,000)
Amortization of net transition obligation	0	0	0
Total recognized in accumulated other comprehensive (income) loss	70,391,000	18,056,000	(33,351,000)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	74,057,000	19,046,000	(25,143,000)
Defined Benefit Plan, Amortization of Net Gains (Losses)	(7,600,000)		
Defined Benefit Plan, Amortization of Net Prior Service Cost (Credit)	(85,000)		
Weighted average assumptions used to determine benefit obligations [Abstract]			
Defined Benefit Plan, Assumptions Used Calculating Benefit Obligation, Discount Rate	4.16%	5.26%	
Defined Benefit Plan Assumptions Used Calculating Benefit Obligation Expected Long Term Return On Assets	7.75%	7.75%	
Defined Benefit Plan, Assumptions Used Calculating Benefit Obligation, Rate of Compensation Increase		4.00%	
Defined Benefit Plan, Weighted Average Assumptions Used in Calculating Net Periodic Benefit Cost [Abstract]			
Defined Benefit Plan, Assumptions Used Calculating Net Periodic Benefit Cost, Discount Rate	5.26%	5.75%	
Defined Benefit Plan, Assumptions Used Calculating Net Periodic Benefit Cost, Expected Long-term Return on Assets	7.75%	8.25%	
Defined Benefit Plan, Assumptions Used Calculating Net Periodic Benefit Cost, Rate of Compensation Increase	4.00%	4.00%	

Defined Benefit Plan, Target Allocation Percentage of Assets, Equity Securities, Range Minimum	60.00%		
Defined Benefit Plan, Target Allocation Percentage of Assets, Equity Securities, Range Maximum	70.00%		
Defined Benefit Plan, Target Allocation Percentage of Assets, Debt Securities, Range Minimum	30.00%		
Defined Benefit Plan, Target Allocation Percentage of Assets, Debt Securities, Range Maximum	40.00%		
Other Postretirement Benefit Plans, Defined Benefit [Member]			
Defined Benefit Plan, Net Periodic Benefit Cost [Abstract]			
Service cost	1,443,000	1,357,000	2,206,000
Interest cost	4,700,000	4,817,000	5,465,000
Expected return on assets	(5,051,000)	(5,512,000)	(5,471,000)
Amortization of prior service cost (credit)	(2,677,000)	(3,303,000)	(2,756,000)
Recognized net actuarial loss	753,000	845,000	970,000
Curtailment loss	0	0	0
Amortization of net transition obligation	2,125,000	2,125,000	2,125,000
Net periodic benefit cost, including amount capitalized	1,293,000	329,000	2,539,000
Less amount capitalized	(50,000)	(92,000)	330,000
Net periodic benefit cost	1,343,000	421,000	2,209,000
Defined Benefit Plan, Amounts Recognized in Other Comprehensive Income (Loss) [Abstract]			
Net (gain) loss	23,863,000	1,462,000	(2,314,000)
Prior service cost (credit)	0	121,000	(9,321,000)
Amortization of actuarial loss	(753,000)	(845,000)	(970,000)
Amortization of prior service (cost) credit	2,677,000	3,303,000	2,756,000
Amortization of net transition obligation	(2,125,000)	(2,125,000)	(2,125,000)
Total recognized in accumulated other comprehensive (income) loss	23,662,000	1,916,000	(11,974,000)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	25,005,000	2,337,000	(9,765,000)
Defined Benefit Plan, Amortization of Net Gains (Losses)	(1,900,000)		
Defined Benefit Plan, Amortization of Net Prior Service Cost (Credit)	(1,100,000)		
Defined Benefit Plan, Amortization of Net Transition Asset (Obligation)	(2,100,000)		
Weighted average assumptions used to determine benefit obligations [Abstract]			
Defined Benefit Plan, Assumptions Used Calculating Benefit Obligation, Discount Rate	4.13%	5.21%	
Defined Benefit Plan Assumptions Used Calculating Benefit Obligation Expected Long Term Return On Assets	6.75%	6.75%	
Defined Benefit Plan, Assumptions Used Calculating Benefit Obligation, Rate of Compensation Increase	4.00%	4.00%	
Defined Benefit Plan, Weighted Average Assumptions Used in Calculating Net Periodic Benefit Cost [Abstract]			
Defined Benefit Plan, Assumptions Used Calculating Net Periodic Benefit Cost, Discount Rate	5.21%	5.75%	

Defined Benefit Plan, Assumptions Used Calculating Net Periodic Benefit Cost, Expected Long-term Return on Assets	6.75%	7.25%
Defined Benefit Plan, Assumptions Used Calculating Net Periodic Benefit Cost, Rate of Compensation Increase	4.00%	4.00%
Percentage excess over the health care cost trend rate that retiree contributions will generally increase each year	6.00%	
Defined Benefit Plan, Target Allocation Percentage of Assets, Equity Securities, Range Minimum	65.00%	
Defined Benefit Plan, Target Allocation Percentage of Assets, Equity Securities, Range Maximum	75.00%	
Defined Benefit Plan, Target Allocation Percentage of Assets, Debt Securities, Range Minimum	25.00%	
Defined Benefit Plan, Target Allocation Percentage of Assets, Debt Securities, Range Maximum	35.00%	
Health care trend rate assumed for next year (minimum)	6.00%	6.00%
Health care trend rate assumed for next year (maximum)	8.00%	8.50%
Health care cost trend rate - ultimate (minimum)	5.00%	5.00%
Health care cost trend rate - ultimate (maximum)	6.00%	6.00%
Year in which ultimate trend rate achieved (minimum)	1999	1999
Year in which ultimate trend rate achieved (maximum)	2017	2017
Defined Benefit Plan, Effect of One Percentage Point Increase on Service and Interest Cost Components	171,000	
Defined Benefit Plan, Effect of One Percentage Point Decrease on Service and Interest Cost Components	(822,000)	
Defined Benefit Plan, Effect of One Percentage Point Increase on Accumulated Postretirement Benefit Obligation	3,175,000	
Defined Benefit Plan, Effect of One Percentage Point Decrease on Accumulated Postretirement Benefit Obligation	$ (10,946,000)	

Income Taxes (Details 3) (USD $)	Dec. 31, 2011	Dec. 31, 2010
Valuation Allowance, Amount	$ 0	$ 0
Deferred tax assets [Abstract]		
Regulatory matters	119,189,000	114,427,000
Accrued pension costs	95,260,000	82,085,000
Asset retirement obligations	26,380,000	24,391,000
Deferred Tax Assets, Tax Deferred Expense, Reserves and Accruals, Legal Settlements	21,788,000	13,622,000
Compensation-related	16,241,000	17,261,000
Other	41,055,000	40,307,000
Total deferred tax assets	319,913,000	292,093,000
Deferred tax liabilities [Abstract]		
Depreciation and basis differences on property, plant and equipment	715,482,000	679,809,000
Basis differences on natural gas and oil producing properties	210,146,000	152,455,000
Regulatory matters	84,963,000	64,017,000
Intangible asset amortization	14,307,000	14,843,000
Other	23,774,000	20,348,000
Total deferred tax liabilities	1,048,672,000	931,472,000
Net deferred income tax liability	$ (728,759,000)	$ (639,379,000)

Commitments and Contingencies	12 Months Ended Dec. 31, 2011
Commitments and Contingencies Disclosure [Abstract]	
Commitments and Contingencies	

Note 19 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. The Company had accrued liabilities of $64.1 million and $45.3 million for contingencies related to litigation and environmental matters as of December 31, 2011 and 2010, respectively, which includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation, which letter of credit expired in November 2010. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand sought compensatory damages of $149.7 million. In June 2010, CEM and Bicent made a demand on Centennial Resources for indemnification under the 2007 purchase and sale agreement for indemnifiable losses, including defense fees and costs arising from LPP's arbitration demand and related to Centennial Resources' ownership of CEM prior to its sale to Bicent. Centennial and Centennial Resources filed a complaint with the Supreme Court of the State of New York in November 2010, against Bicent seeking damages for breach of contract and other relief including specific performance of the 2007 purchase and sale agreement allowing for Centennial Resources' participation in the arbitration proceeding and replacement of the letter of credit. On September 19, 2011, Bicent filed a counterclaim seeking damages against Centennial Resources related to Bicent's costs of defending the LPP arbitration demand which Bicent alleged were in excess of $14.0 million. The arbitration hearing on LPP's claim was held in the third quarter of 2011, and an arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award is recorded in discontinued operations on the Consolidated Statement of Income. The Company intends to vigorously defend against the claims of LPP and Bicent.

Construction Materials In 2009, LTM provided pavement work under a subcontract for reconstruction at the Klamath Falls Airport owned by the City of Klamath Falls, Oregon. In October 2010, the City of Klamath Falls filed a complaint in Oregon Circuit Court against the project's general contractor alleging the work performed by LTM is defective. The general contractor tendered the defense and indemnity of the claim to LTM and its insurance carrier. On January 18, 2011, the general contractor served a third party complaint against LTM seeking indemnity and contribution for damages imposed on the general contractor. LTM filed a fourth-party complaint seeking contribution and indemnity for damages imposed on LTM against the project engineer firm which prepared the specifications for the airport runway. LTM's insurance carrier accepted defense of the complaint against the general contractor and the third party complaint against LTM subject to reservation of its rights under the applicable insurance policy. Damages, including removal and replacement of the paved runway, were estimated by the plaintiff in its complaint as $6.0 million to $11.0 million. The Oregon Circuit Court granted a motion by LTM to dismiss certain of the plaintiff's claims relating to approximately $5.0 million of damages but allowed the plaintiff to amend its complaint. In its amended complaint, the plaintiff asserted new claims with estimated damages of $21.9 million plus interest and attorney fees. LTM and its insurers have been engaged in mediation and settlement discussions with the other parties to resolve this matter.

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

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel Bitter Creek to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of Bitter Creek's pipeline gathering systems in Montana. Bitter Creek resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered Bitter Creek into arbitration. An arbitration hearing was held in August 2010. In October 2010, Bitter Creek was notified that the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, Bitter Creek, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010, which is recorded in operation and maintenance expense on the Consolidated Statement of Income. On April 20, 2011, the Colorado State District Court entered an order denying a motion by Bitter Creek to vacate the arbitration award and granting a motion by SourceGas to confirm the arbitration award as a court judgment. The Colorado State District Court also awarded $293,000 to SourceGas for legal fees and expenses. Bitter Creek filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals on April 28, 2011.

In a related matter, Omimex filed a complaint against Bitter Creek in Montana Seventeenth Judicial District Court in July 2010 alleging Bitter Creek breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging Bitter Creek breached obligations to operate its gathering system as a common carrier under United States and Montana law. Bitter Creek removed the action to the United States District Court for the District of Montana. Expert reports submitted by Omimex contend its damages as a result of the increased operating pressures are $18.8 million to $22.6 million. The Company believes the claims asserted by Omimex are without merit and intends to vigorously defend against the claims.

The Company also is involved in other legal actions in the ordinary course of its business. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above and other legal proceedings will not have a material effect upon the Company's financial position, results of operations or cash flows.

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

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

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

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

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has reserved $1.2 million for remediation of this site.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In September 2011, the EPA issued notice of a proposal to add the site to the National Priorities List. Cascade has met with the EPA to discuss a possible settlement agreement and administrative order for performance of a remedial investigation and feasibility study of the site with the intent of reaching consensus on the scope and schedule for the remedial investigation and feasibility study. Cascade has reserved $6.4 million for remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

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

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

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, 2011, were $27.8 million in 2012, $24.3 million in 2013, $16.4 million in 2014, $8.6 million in 2015, $5.8 million in 2016 and $35.9 million thereafter. Rent expense was $40.7 million, $38.7 million and $43.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage, service and construction materials supply contracts. These commitments range from one to 49 years. The commitments under these contracts as of December 31, 2011, were $478.0 million in 2012, $215.9 million in 2013, $135.8 million in 2014, $71.1 million in 2015, $36.7 million in 2016 and $287.0 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, 2011, 2010 and 2009, were $626.3 million, $611.7 million and $723.1 million.

Guarantees

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

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

WBI Holdings has guaranteed certain of Fidelity's natural gas and oil swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil swap and collar agreements as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil swap and collar agreements at December 31, 2011, expire in the years ranging from 2012 to 2013; 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. The amount outstanding by Fidelity was $4.3 million and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At December 31, 2011, the fixed maximum amounts guaranteed under these agreements aggregated $85.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $42.0 million in 2012; $34.4 million in 2013; $1.3 million in 2014; $100,000 in 2015; $100,000 in 2016; $800,000 in 2018; $300,000 in 2019; $2.6 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 $500,000 and was reflected on the Consolidated Balance Sheet at December 31, 2011. 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, natural gas transportation agreements and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2011, the fixed maximum amounts guaranteed under these letters of credit, aggregated $27.4 million. In 2012 and 2013, $24.1 million and $3.3 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at December 31, 2011.

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, 2011, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.2 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2011, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2011.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries, as well as an arbitration award. 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, 2011, approximately $463 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Summary of Significant Accounting Policies (Details 7) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Cash expenditures for interest and income taxes [Abstract]			
Interest, net of amount capitalized	$ 78,133,000	$ 80,962,000	$ 81,267,000
Income taxes paid (refunded), net	(12,287,000)	46,892,000	39,807,000
Capital Expenditures Not Included in Cash Flows from Investing Activities	$ 24,000,000		

Jointly Owned Facilities (Tables)	12 Months Ended Dec. 31, 2011

Regulated Operations [Abstract]

Company's share of the cost of utility plant in service and related accumulated depreciation for the stations

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:

	2011	2010
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 63,715**	$ 60,404
Less accumulated depreciation	**42,475**	41,136
	$ 21,240	$ 19,268
Coyote Station:		
Utility plant in service	**$131,719**	$131,395
Less accumulated depreciation	**86,788**	84,710
	$ 44,931	$ 46,685
Wygen III:*		
Utility plant in service	**$ 63,300**	$ 63,215
Less accumulated depreciation	**2,106**	838
	$ 61,194	$ 62,377

* Began commercial operation on April 1, 2010.

Business segment data (Details) (USD $)	3 Months Ended								12 Months Ended		
	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2010	Jun. 30, 2010	Mar. 31, 2010	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Segment Reporting Information [Line Items]											
Total external operating revenues	$ 1,065,749,000	$ 1,152,181,000	$ 930,757,000	$ 901,805,000	$ 1,042,551,000	$ 1,125,923,000	$ 906,444,000	$ 834,777,000	$ 4,050,492,000	$ 3,909,695,000	$ 4,176,501,000
Total intersegment operating revenues									0	0	0
Depreciation, depletion and amortization									343,395,000	328,843,000	330,542,000
Interest expense									81,354,000	83,011,000	84,099,000
Income taxes									110,274,000	122,530,000	(96,092,000)
Earnings (loss) on common stock before income (loss) from discontinued operations									225,267,000	243,335,000	(123,959,000)
Income (loss) from discontinued operations, net of tax	(13,080,000) [1]	(126,000)	(168,000)	448,000	(3,361,000)	0	0	0	(12,926,000) [2]	(3,361,000) [2]	0 [2]
Earnings (loss) on common stock									212,341,000	239,974,000	(123,959,000)
Net proceeds from sale or disposition of property and other									40,857,000	78,761,000	26,679,000
Net capital expenditures									481,023,000	495,246,000	428,012,000
Total assets	6,556,125,000				6,303,549,000				6,556,125,000	6,303,549,000	5,990,952,000
Property, plant and equipment	7,646,222,000				7,218,503,000				7,646,222,000	7,218,503,000	
Less accumulated depreciation, depletion and amortization	3,361,208,000				3,103,323,000				3,361,208,000	3,103,323,000	2,872,465,000
Net property, plant and equipment	4,285,014,000				4,115,180,000				4,285,014,000	4,115,180,000	3,894,117,000
Additional information [Abstract]											
Noncash write-down of natural gas and oil properties									0	0	620,000,000
Noncash write-down of natural gas and oil properties, after tax											384,400,000
Natural gas gathering arbitration charge, after tax						16,500,000				16,500,000	
Net noncash transactions included in capital expenditures									24,000,000	17,500,000	
Regulated Operation [Member]											
Segment Reporting Information [Line Items]											
Total external operating revenues									1,343,714,000	1,359,028,000	1,504,269,000
Unregulated Operation [Member]											
Segment Reporting Information [Line Items]											
Total external operating revenues									2,706,778,000	2,550,667,000	2,672,232,000
Electric [Member]											
Segment Reporting Information [Line Items]											
Total external operating revenues									225,468,000	211,544,000	196,171,000
Total intersegment operating revenues									0	0	0
Depreciation, depletion and amortization									32,177,000	27,274,000	24,637,000
Interest expense									13,745,000	12,216,000	9,577,000
Income taxes									7,242,000	11,187,000	8,205,000
Earnings (loss) on common stock before income (loss) from discontinued operations									29,258,000	28,908,000	24,099,000
Net capital expenditures									52,072,000	85,787,000	115,240,000
Total assets	672,940,000 [3]				643,636,000 [3]				672,940,000 [3]	643,636,000 [3]	569,666,000 [3]
Property, plant and equipment	1,068,524,000 [3]				1,027,034,000 [3]				1,068,524,000 [3]	1,027,034,000 [3]	941,791,000 [3]
Natural gas distribution [Member]											
Segment Reporting Information [Line Items]											
Total external operating revenues									907,400,000	892,708,000	1,072,776,000
Total intersegment operating revenues									0	0	0

Depreciation, depletion and amortization			44,641,000	43,044,000	42,723,000
Interest expense			29,444,000	28,996,000	30,656,000
Income taxes			16,931,000	12,171,000	16,331,000
Earnings (loss) on common stock before income (loss) from discontinued operations			38,398,000	36,944,000	30,796,000
Net capital expenditures			70,624,000	75,365,000	43,820,000
Total assets	1,679,091,000 [3]	1,632,012,000 [3]	1,679,091,000 [3]	1,632,012,000 [3]	1,588,144,000 [3]
Property, plant and equipment	1,568,866,000 [3]	1,508,845,000 [3]	1,568,866,000 [3]	1,508,845,000 [3]	1,456,208,000 [3]
Pipeline and energy services [Member]					
Segment Reporting Information [Line Items]					
Total external operating revenues			210,846,000	254,776,000	235,322,000
Total intersegment operating revenues			67,497,000	75,033,000	72,505,000
Depreciation, depletion and amortization			25,502,000	26,001,000	25,581,000
Interest expense			10,516,000	9,064,000	8,896,000
Income taxes			12,912,000	13,933,000	22,982,000
Earnings (loss) on common stock before income (loss) from discontinued operations			23,082,000	23,208,000	37,845,000
Net capital expenditures			45,556,000	14,255,000	70,168,000
Total assets	526,797,000	523,075,000	526,797,000	523,075,000	538,230,000
Property, plant and equipment	719,291,000	683,807,000	719,291,000	683,807,000	675,199,000
Exploration and production [Member]					
Segment Reporting Information [Line Items]					
Total external operating revenues			359,873,000	318,570,000	338,425,000
Total intersegment operating revenues			93,713,000	115,784,000	101,230,000
Depreciation, depletion and amortization			142,645,000	130,455,000	129,922,000
Interest expense			7,445,000	8,580,000	10,621,000
Income taxes			46,298,000	49,034,000	(187,000,000)
Earnings (loss) on common stock before income (loss) from discontinued operations			80,282,000	85,638,000	(296,730,000)
Net capital expenditures			272,855,000	355,845,000	183,140,000
Total assets	1,481,556,000	1,342,808,000	1,481,556,000	1,342,808,000	1,137,628,000
Property, plant and equipment	2,615,146,000	2,356,938,000	2,615,146,000	2,356,938,000	2,028,794,000
Construction materials and contracting [Member]					
Segment Reporting Information [Line Items]					
Total external operating revenues			1,509,538,000	1,445,148,000	1,515,122,000
Total intersegment operating revenues			472,000	0	0
Depreciation, depletion and amortization			85,459,000	88,331,000	93,615,000
Interest expense			16,241,000	19,859,000	20,495,000
Income taxes			11,227,000	13,822,000	25,940,000
Earnings (loss) on common stock before income (loss) from discontinued operations			26,430,000	29,609,000	47,085,000
Net capital expenditures			52,303,000	25,724,000	26,313,000
Total assets	1,374,026,000	1,382,836,000	1,374,026,000	1,382,836,000	1,449,469,000
Property, plant and equipment	1,499,852,000	1,486,375,000	1,499,852,000	1,486,375,000	1,514,989,000
Construction services [Member]					
Segment Reporting Information [Line Items]					
Total external operating revenues			834,918,000	786,802,000	818,685,000
Total intersegment operating revenues			19,471,000	2,298,000	379,000
Depreciation, depletion and amortization			11,399,000	12,147,000	12,760,000
Interest expense			4,473,000	4,411,000	4,490,000
Income taxes			13,426,000	11,456,000	15,189,000
Earnings (loss) on common stock before income (loss) from discontinued operations			21,627,000	17,982,000	25,589,000
Net capital expenditures			9,711,000	14,849,000	12,814,000

Total assets	418,519,000	387,627,000	418,519,000	387,627,000	328,895,000
Property, plant and equipment	124,796,000	122,940,000	124,796,000	122,940,000	116,236,000
Other [Member]					
Segment Reporting Information [Line Items]					
Total external operating revenues			2,449,000	147,000	0
Total intersegment operating revenues			8,997,000	7,580,000	9,487,000
Depreciation, depletion and amortization			1,572,000	1,591,000	1,304,000
Interest expense			0	47,000	43,000
Income taxes			2,238,000	10,927,000	2,261,000
Earnings (loss) on common stock before income (loss) from discontinued operations			6,190,000	21,046,000	7,357,000
Net capital expenditures			18,759,000	2,182,000	3,196,000
Total assets	403,196,000 [4]	391,555,000 [4]	403,196,000 [4]	391,555,000 [4]	378,920,000 [4]
Property, plant and equipment	49,747,000	32,564,000	49,747,000	32,564,000	33,365,000
Intersegment Elimination [Member]					
Segment Reporting Information [Line Items]					
Total intersegment operating revenues			(190,150,000)	(200,695,000)	(183,601,000)
Interest expense			$ (510,000)	$ (162,000)	$ (679,000)

[1] 2011 reflects an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract. For more information, see Note 19.
[2] Reflected in the Other category.
[3] Includes allocations of common utility property.
[4] 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).

Supplemental Financial Information Exploration and Production (Details 6) (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves [Line Items]			
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, Future Cash Inflows	$ 4,188,000	$ 3,790,700	$ 2,991,200
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, Future Production Costs	1,560,300	1,393,000	1,095,600
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, Future Development Costs	285,300	312,500	315,000
Discounted future net cash flows before income taxes	2,342,400	2,085,200	1,580,600
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, Future Income Tax Expense	531,100	432,800	291,000
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, Future Net Cash Flows	1,811,300	1,652,400	1,289,600
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, 10 Percent Annual Discount for Estimated Timing of Cash Flows	832,500	756,300	630,800
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, Standardized Measure	$ 978,800	$ 896,100	$ 658,800

Preferred Stocks (Tables)

12 Months Ended Dec. 31, 2011

Preferred Stocks [Abstract]

Preferred Stock

Preferred stocks at December 31 were as follows:

		2011		2010
		(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

Acquisitions (Details) (USD $)	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Business Acquisition [Line Items]			
Business acquisitions	$ 298,000	$ 106,400,000	$ 22,000,000

Common Stock (Details) (USD $) Share data in Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011
Company's subsidiaries net assets restricted from being used to transfer funds to the Company	$ 2,200,000,000
Credit agreement limitation on company ratio of funded debt to capitalization (excluding subsidiaries)	0.65
Company's (excluding its subsidiaries) net assets restricted from use for dividend payments	$ 136,000,000
Parent Company [Member]	
Shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan (in shares)	23.2
Centennial [Member]	
Maximum distributions to the company as a percentage of consolidated net income after taxes for the preceding fiscal year (in hundredths)	100.00%

Fair Value Measurements Fair Value Measurements (Details 2) (USD $) In Thousands, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Concentration Risks, Percentage [Abstract]		
Percentage investment in common stock of mid-cap companies	33.00%	35.00%
Percentage investment in common stock of small-cap companies	34.00%	33.00%
Percentage investment in common stock of large-cap companies	32.00%	31.00%
Percentage investment in cash and cash equivalents	1.00%	1.00%
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	187,659	236,788
Liabilities, Fair Value Disclosure	18,863	30,911
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Money Market Funds [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	97,500	166,620
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Insurance Investment Contract [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	38,352 [1]	39,541 [2]
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Auction Rate Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	11,400	11,400
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Collateralized Mortgage Backed Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	8,296	
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | US Treasury Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	1,656	
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Commodity derivative instruments - current assets [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		

Assets, Fair Value Disclosure	27,687	15,123
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Commodity derivative instruments assets, noncurrent [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	2,768	4,104
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Commodity derivative instruments - current liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	13,164	24,428
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Commodity derivative instruments - noncurrent liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	937	6,483
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Interest rate derivative instruments - current liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	827	
Fair Value, Measurements, Recurring [Member] | Estimate of Fair Value, Fair Value Disclosure [Member] | Interest rate derivative instruments - noncurrent liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	3,935	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0
Liabilities, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Money Market Funds [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Insurance Investment Contract [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0 [1]	0 [2]
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Auction Rate Securities [Member]		

Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Collateralized Mortgage Backed Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | US Treasury Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Commodity derivative instruments - current assets [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Commodity derivative instruments assets, noncurrent [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Commodity derivative instruments - current liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Commodity derivative instruments - noncurrent liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Interest rate derivative instruments - current liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	0	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Interest rate derivative instruments - noncurrent liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	0	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		

Assets, Fair Value Disclosure	187,659	236,788
Liabilities, Fair Value Disclosure	18,863	30,911
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Money Market Funds [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	97,500	166,620
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Insurance Investment Contract [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	38,352 [1]	39,541 [2]
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Auction Rate Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	11,400	11,400
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Collateralized Mortgage Backed Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	8,296	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | US Treasury Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	1,656	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Commodity derivative instruments - current assets [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	27,687	15,123
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Commodity derivative instruments assets, noncurrent [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	2,768	4,104
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Commodity derivative instruments - current liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	13,164	24,428
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Commodity derivative instruments - noncurrent liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		

Liabilities, Fair Value Disclosure	937	6,483
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Interest rate derivative instruments - current liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	827	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Interest rate derivative instruments - noncurrent liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	3,935	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0
Liabilities, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Money Market Funds [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Insurance Investment Contract [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0 [1]	0 [2]
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Auction Rate Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Collateralized Mortgage Backed Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | US Treasury Securities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Commodity derivative instruments - current assets [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0

Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Commodity derivative instruments assets, noncurrent [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Assets, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Commodity derivative instruments - current liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Commodity derivative instruments - noncurrent liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	0	0
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Interest rate derivative instruments - current liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	0	
Fair Value, Measurements, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Interest rate derivative instruments - noncurrent liabilities [Member]		
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]		
Liabilities, Fair Value Disclosure	0	

[1] The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

[2] The insurance investment contract invests approximately 35 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 31 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

Summary of Significant Accounting Policies (Details 4) (USD $)	12 Months Ended				
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009	Dec. 31, 2008	Mar. 31, 2009
Natural gas and oil properties [Abstract]					
Discount rate used in calculating present value of future net cash flows from proved reserves (in hundredths)	10.00%				
Noncash write-down of natural gas and oil properties	$ 0	$ 0	$ 620,000,000		
Noncash write-downs of natural gas and oil production properties, after tax			384,400,000		
Additional write-downs of its natural gas and oil properties that would have been recognized without effects of cash flow hedges					107,900,000
Additional write-downs of its natural gas and oil properties that would have been recognized without effects of cash flow hedges, after tax					66,900,000
Natural gas and oil properties not subject to amortization [Abstract]					
Acquisition	185,773,000				
Development	9,938,000				
Exploration	27,439,000				
Capitalized interest	9,312,000				
Total costs not subject to amortization	232,462,000	182,402,000	178,214,000		
Acquisition Costs, Period Cost	50,721,000	71,315,000	988,000	62,749,000	
Development Costs, Period Cost	9,689,000	156,000	2,000	91,000	
Exploration Costs, Period Cost	24,389,000	2,710,000	72,000	268,000	
Interest Costs, Capitalized During Period	3,539,000	3,096,000	44,000	2,633,000	
Capitalized Costs of Unproved Properties Excluded from Amortization, Period Cost	$ 88,338,000	$ 77,277,000	$ 1,106,000	$ 65,741,000	
Time period for evaluating the majority of costs not subject to amortization (in years)	five years				

Discontinued Operations	12 Months Ended Dec. 31, 2011
Discontinued Operations and Disposal Groups [Abstract]	
Discontinued Operations	Discontinued Operations In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In 2011, the Company also incurred legal expenses related to this matter and in the first quarter had an income tax benefit related to favorable resolution of certain tax matters. In the fourth quarter of 2010, the Company established an accrual for an indemnification claim by Bicent. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For further information, see Note 19.

Fair Value Measurements (Details 3) (USD $) In Thousands, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Carrying (Reported) Amount, Fair Value Disclosure [Member]		
Fair Value, Balance Sheet Grouping, Financial Statement Captions [Line Items]		
Long-term debt	$ 1,424,678	$ 1,506,752
Estimate of Fair Value, Fair Value Disclosure [Member]		
Fair Value, Balance Sheet Grouping, Financial Statement Captions [Line Items]		
Long-term debt	$ 1,592,807	$ 1,621,184

Supplemental Financial Information (Unaudited) (Tables)	3 Months Ended	12 Months Ended
	Dec. 31, 2011	Dec. 31, 2011
Quarterly Financial Information Disclosure [Abstract]		
Schedule of Proved Developed and Undeveloped Oil and Gas Reserve Quantities [Table Text Block]		The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2011, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	448,397	32,867	645,596
Production	(45,598)	(3,500)	(66,596)
Extensions and discoveries	28,221	6,138	65,049
Improved recovery	—	—	—
Purchases of proved reserves	54	239	1,486
Sales of proved reserves	—	—	—
Revisions of previous estimates	(51,247)	(1,397)	(59,627)
Balance at end of year	379,827	34,347	585,908

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

- Extensions and discoveries of 65.0 Bcfe primarily due to drilling activity at the Company's Bakken and Big Horn properties
- Revisions of previous estimates of (59.6) Bcfe, largely the result of a reduction in PUD reserves of 53.6 Bcfe resulting principally in the Company's Bowdoin, Baker, Coalbed, East Texas and Big Horn Basin properties. The remaining negative revisions were a reduction in PDP natural gas reserves.

The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2010, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed			

and undeveloped reserves:			
Balance at beginning of year	448,425	34,216	653,724
Production	(50,391)	(3,262)	(69,963)
Extensions and discoveries	36,191	3,389	56,523
Improved recovery	—	—	—
Purchases of proved reserves	55,119	979	60,991
Sales of proved reserves	(92)	(18)	(202)
Revisions of previous estimates	(40,855)	(2,437)	(55,477)
Balance at end of year	448,397	32,867	645,596

Significant changes in proved reserves for the year ended December 31, 2010, include:

- Extensions and discoveries of 56.5 Bcfe primarily due to drilling activity at the Company's Bakken, Baker, Bowdoin and east Texas properties
- Purchases of proved reserves of 61.0 Bcfe as a result of the Company's acquisition of natural gas properties in the Green River Basin in Wyoming, as discussed in Note 2
- Revisions of previous estimates of (55.5) Bcfe largely the result of negative performance revisions resulting primarily from new information gained from production history and developmental drilling activity in the Company's Bowdoin, south Texas, Baker and east Texas properties and removal of PUD reserves due to the five-year limitation rule, partially offset by positive revisions due to increased natural gas and oil prices

The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2009, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	604,282	34,348	810,371
Production	(56,632)	(3,111)	(75,299)

Extensions and discoveries	26,882	2,569	42,297
Improved recovery	—	—	—
Purchases of proved reserves	—	—	—
Sales of proved reserves	(22)	(248)	(1,510)
Revisions of previous estimates	(126,085)	658	(122,135)
Balance at end of year	448,425	34,216	653,724

Significant changes in proved reserves for the year ended December 31, 2009, include:

- Extensions and discoveries of 42.3 Bcfe primarily due to drilling activity at the Company's Bowdoin, Bakken, Baker and east Texas properties
- Revisions of previous estimates of (122.1) Bcfe largely the result of negative revisions resulting from decreased natural gas and oil prices and negative performance revisions resulting primarily from new information gained from production history and developmental drilling activity in the Company's east Texas and south Texas properties

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

	2011	2010	2009
Proved developed reserves:			
Natural Gas (MMcf)	**303,495**	334,911	321,561
Oil (MBbls)	**28,878**	26,586	26,794
Total (MMcfe)	**476,763**	494,426	482,329
PUD reserves:			
Natural Gas (MMcf)	**76,332**	113,486	126,864
Oil (MBbls)	**5,469**	6,281	7,422
Total (MMcfe)	**109,145**	151,170	171,395
Total proved reserves:			
Natural Gas (MMcf)	**379,827**	448,397	448,425
Oil (MBbls)	**34,347**	32,867	34,216
Total (MMcfe)	**585,908**	645,596	653,724

Capitalized Costs Relating to Oil and Gas Producing

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization

Activities Disclosure [Table Text Block]

related to natural gas and oil producing activities at December 31:

	2011	2010	2009
	(In thousands)		
Subject to amortization	**$2,345,114**	$2,138,565	$1,815,380
Not subject to amortization	**232,462**	182,402	178,214
Total capitalized costs	**2,577,576**	2,320,967	1,993,594
Less accumulated depreciation, depletion and amortization	**1,229,654**	1,093,723	969,630
Net capitalized costs	**$1,347,922**	$1,227,244	$1,023,964

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

Cost Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities Disclosure [Table Text Block]

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

Years ended December 31,	2011 *	2010 *	2009 *
	(In thousands)		
Acquisitions:			
Proved properties	**$ 3,999**	$ 89,733	$ 3,879
Unproved properties	**63,354**	92,100	8,771
Exploration	**41,775**	33,226	33,123
Development	**161,647**	139,733	135,202
Total capital expenditures	**$270,775**	$354,792	$180,975

* Excludes net additions/(reductions) to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of natural gas and oil wells, as discussed in Note 10, of $(1.8) million, $11.1 million and $2.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Results of Operations for Oil and Gas Producing Activities Disclosure [Table Text Block]

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,	2011	2010	2009
	(In thousands)		
Revenues:			
Sales to affiliates	**$ 93,713**	$115,784	$ 101,230

Sales to external customers	**359,873**	318,565	338,425
Production costs	**140,606**	127,403	123,148
Depreciation, depletion and amortization*	**139,539**	127,266	126,278
Write-down of natural gas and oil properties	—	—	620,000
Pretax income	**173,441**	179,680	(429,771)
Income tax expense	**63,655**	66,293	(164,216)
Results of operations for producing activities	**$109,786**	$113,387	$(265,555)

* Includes accretion of discount for asset retirement obligations of $3.6 million, $3.2 million and $2.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, as discussed in Note 10.

Quarterly financial data

The following unaudited information shows selected items by quarter for the years 2011 and 2010:

	First Quarter	Second Quarter	Third Quarter *	Fourth Quarter **
	(In thousands, except per share amounts)			
2011				
Operating revenues	**$901,805**	**$930,757**	**$1,152,181**	**$1,065,749**
Operating expenses	**823,739**	**848,454**	**1,032,760**	**939,172**
Operating income	**78,066**	**82,303**	**119,421**	**126,577**
Income from continuing operations	**42,529**	**45,235**	**64,100**	**74,088**
Income (loss) from discontinued operations, net of tax	**448**	**(168)**	**(126)**	**(13,080)**
Net income	**42,977**	**45,067**	**63,974**	**61,008**
Earnings per common share - basic:				
Earnings before discontinued operations	**.22**	**.24**	**.34**	**.39**
Discontinued operations, net of tax	**.01**	—	—	**(.07)**
Earnings per common share - basic	**.23**	**.24**	**.34**	**.32**
Earnings per common share - diluted:				

Earnings before discontinued operations	**.22**	**.24**	**.34**	**.39**
Discontinued operations, net of tax	**.01**	**—**	**—**	**(.07)**
Earnings per common share - diluted	**.23**	**.24**	**.34**	**.32**
Weighted average common shares outstanding:				
Basic	**188,671**	**188,794**	**188,794**	**188,794**
Diluted	**188,815**	**188,968**	**188,797**	**188,932**
2010				
Operating revenues	$834,777	$906,444	$1,125,923	$1,042,551
Operating expenses	751,848	817,782	1,016,961	912,377
Operating income	82,929	88,662	108,962	130,174
Income from continuing operations	41,772	48,938	61,010	92,300
Loss from discontinued operations, net of tax	—	—	—	(3,361)
Net income	41,772	48,938	61,010	88,939
Earnings per common share - basic:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share - basic	.22	.26	.32	.47
Earnings per common share - diluted:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share - diluted	.22	.26	.32	.47
Weighted average common				

shares outstanding:				
Basic	187,963	188,129	188,170	188,281
Diluted	188,220	188,267	188,338	188,374

* 2010 reflects a natural gas gathering arbitration charge of $16.5 million (after tax). For more information, see Note 19.

** 2011 reflects an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract. For more information, see Note 19. 2010 reflects a $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines. For more information, see Note 4.

Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Table Text Block]

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:

	2011	2010	2009
	(In thousands)		
Future cash inflows	**$4,188,000**	$3,790,700	$2,991,200
Future production costs	**1,560,300**	1,393,000	1,095,600
Future development costs	**285,300**	312,500	315,000
Future net cash flows before income taxes	**2,342,400**	2,085,200	1,580,600
Future income tax expense	**531,100**	432,800	291,000
Future net cash flows	**1,811,300**	1,652,400	1,289,600
10% annual discount for estimated timing of cash flows	**832,500**	756,300	630,800
Discounted future net cash flows relating to proved natural gas and oil reserves	**$ 978,800**	$ 896,100	$ 658,800

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

	2011	2010	2009
	(In thousands)		
Beginning of year	**$ 896,100**	$ 658,800	$ 969,800
Net revenues from production	**(301,500)**	(270,000)	(200,900)
Net change in sales prices and	**82,300**	362,400	(364,800)

production costs related to future production			
Extensions and discoveries, net of future production-related costs	**226,300**	130,500	70,500
Improved recovery, net of future production-related costs	**—**	—	—
Purchases of proved reserves, net of future production-related costs	**9,500**	99,800	—
Sales of proved reserves	**—**	(500)	(1,100)
Changes in estimated future development costs	**51,100**	34,100	43,600
Development costs incurred during the current year	**56,300**	43,100	46,400
Accretion of discount	**105,000**	76,500	115,900
Net change in income taxes	**(55,800)**	(103,300)	142,800
Revisions of previous estimates	**(92,900)**	(132,000)	(155,500)
Other	**2,400**	(3,300)	(7,900)
Net change	**82,700**	237,300	(311,000)
End of year	**$ 978,800**	$ 896,100	$ 658,800

Summary of Significant Accounting Policies (Policies)	12 Months Ended Dec. 31, 2011
Accounting Policies [Abstract]	
Basis of presentation	**Basis of presentation** The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities. The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses. The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals. Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses. Management has also evaluated the impact of events occurring after December 31, 2011, up to the date of issuance of these consolidated financial statements.
Cash and cash equivalents	**Cash and cash equivalents** The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.
Accounts receivable and allowance for doubtful accounts	**Accounts receivable and allowance for doubtful accounts** Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $29.8 million and $21.6 million as of December 31, 2011 and 2010, respectively. For more information, see Percentage-of-completion method in this note. The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2011 and 2010, was $12.4 million and $15.3 million, respectively.
Inventories and natural gas in storage	**Inventories and natural gas in storage** Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated

operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

	2011	2010
	(In thousands)	
Aggregates held for resale	**$ 78,518**	$ 79,894
Materials and supplies	**61,611**	57,324
Natural gas in storage (current)	**36,578**	34,557
Asphalt oil	**32,335**	25,234
Merchandise for resale	**32,165**	30,182
Other	**32,998**	25,706
Total	**$ 274,205**	$ 252,897

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $50.3 million and $48.0 million at December 31, 2011 and 2010, respectively.

Investments

Investments

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

Property, plant and equipment

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and production properties as described in 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 $15.1 million, $17.6 million and $17.4 million in 2011, 2010 and 2009, 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 exploration and 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:

	2011	2010	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			

Generation	**$ 546,783**	$ 538,071	47
Distribution	**255,232**	243,205	36
Transmission	**179,580**	161,972	44
Other	**86,929**	83,786	13
Natural gas distribution:			
Distribution	**1,257,360**	1,223,239	38
Other	**311,506**	285,606	23
Pipeline and energy services:			
Transmission	**386,227**	357,395	52
Gathering	**42,378**	41,931	19
Storage	**41,908**	33,967	51
Other	**36,179**	33,938	29
Nonregulated:			
Pipeline and energy services:			
Gathering	**198,864**	203,064	17
Other	**13,735**	13,512	10
Exploration and production:			
Natural gas and oil properties	**2,577,576**	2,320,967	*
Other	**37,570**	35,971	9
Construction materials and contracting:			
Land	**126,790**	124,018	—
Buildings and improvements	**67,627**	65,003	20
Machinery, vehicles and equipment	**902,136**	899,365	12
Construction in progress	**8,085**	4,879	—
Aggregate reserves	**395,214**	393,110	**
Construction services:			
Land	**4,706**	4,526	—
Buildings and improvements	**15,001**	14,101	22
Machinery, vehicles and equipment	**95,891**	94,252	7
Other	**9,198**	10,061	4
Other:			
Land	**2,837**	2,837	—
Other	**46,910**	29,727	24
Less accumulated depreciation, depletion and amortization	**3,361,208**	3,103,323	
Net property, plant and equipment	**$ 4,285,014**	$ 4,115,180	

* Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $2.04, $1.77 and $1.64 for the years ended December 31, 2011, 2010 and 2009, respectively. Includes natural gas and oil properties accounted for under the full-cost method, of which $232.5 and $182.4 million were excluded from amortization at December 31, 2011 and 2010, respectively.

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

Impairment of long-lived assets

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 2011, 2010 and 2009. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

Goodwill

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

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach. If the fair value of a reporting unit is less than its carrying value, step two of the goodwill impairment test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the affected reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2011, 2010 and 2009, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded. For more information on goodwill, see Note 5.

Natural gas and oil properties

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 generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, 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 at March 31, 2009, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2009. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-down amounted to $620.0 million ($384.4 million after tax) for the year ended December 31, 2009.

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, 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, 2011, 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, 2011, 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, 2011, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2011	2010	2009	2008 and prior
		(In thousands)			
Acquisition	$185,773	$ 50,721	$ 71,315	$ 988	$ 62,749
Development	9,938	9,689	156	2	91
Exploration	27,439	24,389	2,710	72	268
Capitalized interest	9,312	3,539	3,096	44	2,633
Total costs not subject to amortization	$232,462	$ 88,338	$ 77,277	$ 1,106	$ 65,741

Costs not subject to amortization as of December 31, 2011, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Texas properties, Niobrara play, the Paradox Basin, the Green River Basin and the Big Horn Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue 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 $80.2 million and $87.3 million at December 31, 2011 and 2010, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

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 $54.3 million and $46.6 million at December 31, 2011 and 2010, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $79.1 million and $65.2 million at December 31, 2011 and 2010, 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 $51.5 million and $51.1 million at December 31, 2011 and 2010, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $49.3 million and $50.4 million at December 31, 2011 and 2010, respectively. The long-term retainage which was included in deferred charges and other assets - other was $2.2 million and $700,000 at December 31, 2011 and 2010, 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 sales of 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. 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. For more information, see Note 8.

Asset retirement obligations

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

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $45.1 million and $37.0 million at December 31, 2011 and 2010, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $2.6 million and $6.6 million at December 31, 2011 and 2010, respectively, which is included in prepayments and other current assets.

Insurance

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

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 positions in income taxes.

Foreign currency translation adjustment

Foreign currency translation adjustment

The functional currency of the Company's investment in ECTE, 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 an average of the 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

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 2011 and 2010, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury. Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2011	2010	2009 *
	(In thousands)		
Weighted average common shares outstanding - basic	**188,763**	188,137	185,175
Effect of dilutive stock options and performance share awards	**142**	92	—

Weighted average common shares outstanding - diluted	**188,905**	188,229	185,175

* Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.

Use of estimates

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 acquisition 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, Supplemental Disclosures [Text Block]

Cash flow information

Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	**2011**	2010	2009
		(In thousands)	
Interest, net of amount capitalized	**$ 78,133**	$ 80,962	$ 81,267
Income taxes paid (refunded), net	**$ (12,287)**	$ 46,892	$ 39,807

For the year ended December 31, 2011, cash flows from investing activities do not include $24.0 million of capital expenditures, including amounts being financed with accounts payable, and therefore, do not have an impact on cash flows for the period.

Schedule of New Accounting Pronouncements and Changes in Accounting Principles [Table Text Block]

New accounting standards

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 were effective on January 1, 2011. The guidance requires additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance is effective for the Company on January 1, 2012. The guidance will require additional disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The guidance, except for the portion that was indefinitely deferred, is effective for the Company on January 1, 2012, and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosure, but it will not impact the Company's results of operations, financial position or cash flows.

Disclosures about an Employer's Participation in a Multiemployer Plan In September 2011, the FASB issued guidance on an employer's participation in multiemployer benefit plans. The guidance was issued to enhance the transparency of disclosures about the significant multiemployer plans in which employers participate, the level of the employer's participation in those plans, the financial health of the plans and the nature of the employer's commitments to the plans. This guidance was effective for the Company on December 31, 2011, and must be applied retrospectively. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Comprehensive Income (Loss) Note [Text Block]

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 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 loss, and their related tax effects for the years ended December 31 were as follows:

	2011	2010	2009
		(In thousands)	
Other comprehensive 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 $4,683, $(1,867) and $(2,509) in 2011, 2010 and 2009, respectively	**$ 7,900**	$ (3,077)	$ (4,094)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $0, $(2,305) and $29,170 in 2011, 2010 and 2009, respectively	**—**	(3,750)	47,590
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**7,900**	673	(51,684)
Postretirement liability adjustment, net of tax of $(13,573), $(3,609) and $6,291 in 2011, 2010 and 2009, respectively	**(22,427)**	(5,730)	9,918

Foreign currency translation adjustment, net of tax of $(832), $(3,486) and $6,814 in 2011, 2010 and 2009, respectively	**(1,295)**	(5,371)	10,568
Net unrealized gains on available-for-sale investments, net of tax of $44 in 2011	**82**	—	—
Total other comprehensive loss	**$ (15,740)**	$ (10,428)	$ (31,198)

The after-tax components of accumulated other comprehensive loss as of December 31, 2011, 2010 and 2009, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2009	$ (2,298)	$ (25,163)	$ 6,628	$ —	$ (20,833)
Balance at December 31, 2010	$ (1,625)	$ (30,893)	$ 1,257	$ —	$ (31,261)
Balance at December 31, 2011	**$ 6,275**	**$ (53,320)**	**$ (38)**	**$ 82**	**$ (47,001)**

Schedule II Valuation and Qualifying Accounts	12 Months Ended Dec. 31, 2011
Valuation and Qualifying Accounts [Abstract]	
Schedule II - Valuation and Qualifying Accounts	Consolidated Valuation and Qualifying Accounts

For the years ended December 31, 2011, 2010 and 2009

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other *	Deductions **	Balance at End of Year
		(In thousands)			
Allowance for doubtful accounts:					
2011	**$ 15,284**	**$ 3,977**	**$ 2,112**	**$ 8,966**	**$ 12,407**
2010	16,649	5,044	2,300	8,709	15,284
2009	13,691	12,152	1,412	10,606	16,649

* 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.

Schedule II Valuation and Qualifying Accounts (Details) (Allowance for Doubtful Accounts [Member], USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Allowance for Doubtful Accounts [Member]			
Allowance for doubtful accounts:			
Balance, beginning of period	$ 15,284	$ 16,649	$ 13,691
Charged to Costs and Expenses	3,977	5,044	12,152
Other	2,112	2,300	1,412
Deductions	8,966	8,709	10,606
Balance, end of period	$ 12,407	$ 15,284	$ 16,649

Goodwill and Other Intangible Assets (Details 2) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Finite-Lived Intangible Assets [Line Items]			
Intangible Assets, Net (Excluding Goodwill)	$ 20,843,000	$ 25,271,000	
Amortization of Intangible Assets	3,700,000	4,200,000	5,000,000
Estimated amortization expense for amortizable intangible assets			
2012	3,800,000		
2013	3,700,000		
2014	3,300,000		
2015	2,600,000		
2016	2,100,000		
Thereafter	5,300,000		
Customer Relationships [Member]			
Finite-Lived Intangible Assets [Line Items]			
Other amortizable intangible assets	21,702,000	24,942,000	
Accumulated amortization	(10,392,000)	(11,625,000)	
Intangible Assets, Net (Excluding Goodwill)	11,310,000	13,317,000	
Noncompete Agreements [Member]			
Finite-Lived Intangible Assets [Line Items]			
Other amortizable intangible assets	7,685,000	9,405,000	
Accumulated amortization	(5,371,000)	(6,425,000)	
Intangible Assets, Net (Excluding Goodwill)	2,314,000	2,980,000	
Other [Member}			
Finite-Lived Intangible Assets [Line Items]			
Other amortizable intangible assets	11,442,000	13,217,000	
Accumulated amortization	(4,223,000)	(4,243,000)	
Intangible Assets, Net (Excluding Goodwill)	$ 7,219,000	$ 8,974,000	

Summary of Significant Accounting Policies (Details) (USD $) In Millions, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Accounts receivable and allowance for doubtful accounts [Abstract]		
Balance of receivables past due 90 days or more	$ 29.8	$ 21.6
Allowance for doubtful accounts	$ 12.4	$ 15.3

Summary of Significant Accounting Policies (Tables)

12 Months Ended Dec. 31, 2011

Accounting Policies [Abstract]

Inventories

	2011	2010
	(In thousands)	
Aggregates held for resale	**$ 78,518**	$ 79,894
Materials and supplies	**61,611**	57,324
Natural gas in storage (current)	**36,578**	34,557
Asphalt oil	**32,335**	25,234
Merchandise for resale	**32,165**	30,182
Other	**32,998**	25,706
Total	**$ 274,205**	$ 252,897

Property, plant and equipment

	2011	2010	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	**$ 546,783**	$ 538,071	47
Distribution	**255,232**	243,205	36
Transmission	**179,580**	161,972	44
Other	**86,929**	83,786	13
Natural gas distribution:			
Distribution	**1,257,360**	1,223,239	38
Other	**311,506**	285,606	23
Pipeline and energy services:			
Transmission	**386,227**	357,395	52
Gathering	**42,378**	41,931	19
Storage	**41,908**	33,967	51
Other	**36,179**	33,938	29
Nonregulated:			
Pipeline and energy services:			
Gathering	**198,864**	203,064	17
Other	**13,735**	13,512	10
Exploration and production:			
Natural gas and oil properties	**2,577,576**	2,320,967	*
Other	**37,570**	35,971	9
Construction materials and contracting:			
Land	**126,790**	124,018	—
Buildings and improvements	**67,627**	65,003	20
Machinery, vehicles and equipment	**902,136**	899,365	12
Construction in progress	**8,085**	4,879	—

Aggregate reserves	**395,214**	393,110	**
Construction services:			
Land	**4,706**	4,526	—
Buildings and improvements	**15,001**	14,101	22
Machinery, vehicles and equipment	**95,891**	94,252	7
Other	**9,198**	10,061	4
Other:			
Land	**2,837**	2,837	—
Other	**46,910**	29,727	24
Less accumulated depreciation, depletion and amortization	**3,361,208**	3,103,323	
Net property, plant and equipment	**$ 4,285,014**	$ 4,115,180	

* Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $2.04, $1.77 and $1.64 for the years ended December 31, 2011, 2010 and 2009, respectively. Includes natural gas and oil properties accounted for under the full-cost method, of which $232.5 and $182.4 million were excluded from amortization at December 31, 2011 and 2010, respectively.

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

Summary of natural gas and oil properties not subject to amortization

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2011, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2011	2010	2009	2008 and prior
	(In thousands)				
Acquisition	$185,773	$ 50,721	$ 71,315	$ 988	$ 62,749
Development	9,938	9,689	156	2	91
Exploration	27,439	24,389	2,710	72	268
Capitalized interest	9,312	3,539	3,096	44	2,633
Total costs not subject to amortization	$232,462	$ 88,338	$ 77,277	$ 1,106	$ 65,741

Schedule of Earnings Per Share Reconciliation [Table Text Block]

Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2011	2010	2009 *
	(In thousands)		
Weighted average common shares outstanding - basic	**188,763**	188,137	185,175
Effect of dilutive stock options and performance share awards	**142**	92	—
Weighted average common shares outstanding - diluted	**188,905**	188,229	185,175

* Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.

Cash expenditures for interest and income taxes

Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	**2011**	2010	2009
	(In thousands)		
Interest, net of amount capitalized	**$ 78,133**	$ 80,962	$ 81,267

Income taxes paid (refunded), net	**$ (12,287)**	$ 46,892	$ 39,807

Components of other comprehensive income (loss) and their related tax effects

The components of other comprehensive loss, and their related tax effects for the years ended December 31 were as follows:

	2011	2010	2009
	(In thousands)		
Other comprehensive 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 $4,683, $(1,867) and $(2,509) in 2011, 2010 and 2009, respectively	**$ 7,900**	$ (3,077)	$ (4,094)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $0, $(2,305) and $29,170 in 2011, 2010 and 2009, respectively	**—**	(3,750)	47,590
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**7,900**	673	(51,684)
Postretirement liability adjustment, net of tax of $(13,573), $(3,609) and $6,291 in 2011, 2010 and 2009, respectively	**(22,427)**	(5,730)	9,918
Foreign currency translation adjustment, net of tax of $(832), $(3,486) and $6,814 in 2011, 2010 and 2009, respectively	**(1,295)**	(5,371)	10,568
Net unrealized gains on available-for-sale investments, net of tax of $44 in 2011	**82**	—	—
Total other comprehensive loss	**$ (15,740)**	$ (10,428)	$ (31,198)

After-tax components of accumulated other comprehensive income (loss)

The after-tax components of accumulated other comprehensive loss as of December 31, 2011, 2010 and 2009, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2009	$ (2,298)	$ (25,163)	$ 6,628	$ —	$ (20,833)
Balance at December 31, 2010	$ (1,625)	$ (30,893)	$ 1,257	$ —	$ (31,261)
Balance at December 31, 2011	**$ 6,275**	**$ (53,320)**	**$ (38)**	**$ 82**	**$ (47,001)**

Goodwill and Other Intangible Assets (Tables)	12 Months Ended Dec. 31, 2011

Goodwill [Line Items]

Changes in the Carrying Amount of Goodwill

The changes in the carrying amount of goodwill for the year ended December 31, 2011, were as follows:

	Balance as of January 1, 2011 *	Goodwill Acquired During the Year **	Balance as of December 31, 2011 *
	(In thousands)		
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	9,737	—	9,737
Exploration and production	—	—	—
Construction materials and contracting	176,290	—	176,290
Construction services	102,870	298	103,168
Other	—	—	—
Total	$ 634,633	$ 298	$ 634,931

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

** Includes a purchase price adjustment that was not material related to an acquisition in a prior period.

The changes in the carrying amount of goodwill for the year ended December 31, 2010, were as follows:

	Balance as of January 1, 2010 *	Goodwill Acquired During the Year **	Balance as of December 31, 2010 *
	(In thousands)		
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	7,857	1,880	9,737
Exploration and production	—	—	—
Construction materials and contracting	175,743	547	176,290
Construction services	100,127	2,743	102,870
Other	—	—	—
Total	$ 629,463	$ 5,170	$ 634,633

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

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

Other Amortizable Intangible Assets

Other amortizable intangible assets at December 31 were as follows:

	2011	2010
	(In thousands)	

Customer relationships	**$ 21,702**	$ 24,942
Accumulated amortization	**(10,392)**	(11,625)
	11,310	13,317
Noncompete agreements	**7,685**	9,405
Accumulated amortization	**(5,371)**	(6,425)
	2,314	2,980
Other	**11,442**	13,217
Accumulated amortization	**(4,223)**	(4,243)
	7,219	8,974
Total	**$ 20,843**	$ 25,271

Acquisitions	12 Months Ended Dec. 31, 2011
Business Combinations [Abstract]	
Acquisitions	

Acquisitions

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

In 2010, the Company acquired natural gas properties in the Green River Basin in southwest Wyoming. The total purchase consideration for these properties and purchase price adjustments with respect to certain other acquisitions made prior to 2010, consisting of the Company's common stock and cash, was $106.4 million.

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.

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

Regulatory Assets and Liabilities (Tables)	12 Months Ended Dec. 31, 2011
Regulatory Assets and Liabilities Disclosure [Abstract]	
Regulatory Assets and Liabilities	The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period *	2011	2010
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	**171,492**	103,818
Deferred income taxes	**	**119,189**	114,427
Taxes recoverable from customers (a)	—	**12,433**	11,961
Plant costs (a)	Over plant lives	**10,256**	9,964
Long-term debt refinancing costs (a)	Up to 27 years	**10,112**	11,101
Costs related to identifying generation development (a)	Up to 15 years	**9,817**	13,777
Natural gas supply derivatives (b)	Up to 1 year	**437**	9,359
Natural gas cost recoverable through rate adjustments (b)	Up to 28 months	**2,622**	6,609
Other (a) (b)	Largely within 1 year	**22,651**	35,225
Total regulatory assets		**359,009**	316,241
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		**289,972**	276,652
Deferred income taxes**		**84,963**	64,017
Natural gas costs refundable through rate adjustments (d)		**45,064**	36,996
Taxes refundable to customers (c)		**31,837**	19,352
Other (c) (d)		**8,393**	16,080
Total regulatory liabilities		**460,229**	413,097
Net regulatory position		**(101,220)**	(96,856)

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

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

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

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

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

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

(e) Recovered as expense is incurred.

Jointly Owned Facilities (Details)	Dec. 31, 2011
Big Stone Station [Member]	
Jointly Owned Utility Plant Interests [Line Items]	
Company's percentage ownership interests in the assets, liabilities and expenses of the Joint ventures or affiliates.	22.70%
Coyote Station [Member]	
Jointly Owned Utility Plant Interests [Line Items]	
Company's percentage ownership interests in the assets, liabilities and expenses of the Joint ventures or affiliates.	25.00%
Wygen III [Member]	
Jointly Owned Utility Plant Interests [Line Items]	
Company's percentage ownership interests in the assets, liabilities and expenses of the Joint ventures or affiliates.	25.00%

Business segment data (Tables)	12 Months Ended Dec. 31, 2011

Segment Reporting [Abstract]

Information on the Company's businesses

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:

	2011	2010	2009
		(In thousands)	
External operating revenues:			
Electric	**$ 225,468**	$ 211,544	$ 196,171
Natural gas distribution	**907,400**	892,708	1,072,776
Pipeline and energy services	**210,846**	254,776	235,322
	1,343,714	1,359,028	1,504,269
Exploration and production	**359,873**	318,570	338,425
Construction materials and contracting	**1,509,538**	1,445,148	1,515,122
Construction services	**834,918**	786,802	818,685
Other	**2,449**	147	—
	2,706,778	2,550,667	2,672,232
Total external operating revenues	**$4,050,492**	$3,909,695	$4,176,501

	2011	2010	2009
		(In thousands)	
Intersegment operating revenues:			
Electric	**$ —**	$ —	$ —
Natural gas distribution	**—**	—	—
Pipeline and energy services	**67,497**	75,033	72,505
Exploration and production	**93,713**	115,784	101,230
Construction materials and contracting	**472**	—	—
Construction services	**19,471**	2,298	379
Other	**8,997**	7,580	9,487
Intersegment eliminations	**(190,150)**	(200,695)	(183,601)
Total intersegment operating revenues	**$ —**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	**$ 32,177**	$ 27,274	$ 24,637
Natural gas distribution	**44,641**	43,044	42,723
Pipeline and energy services	**25,502**	26,001	25,581
Exploration and production	**142,645**	130,455	129,922
Construction materials and contracting	**85,459**	88,331	93,615
Construction services	**11,399**	12,147	12,760
Other	**1,572**	1,591	1,304
Total depreciation, depletion and amortization	**$ 343,395**	$ 328,843	$ 330,542

	2011	2010	2009
Interest expense:			
Electric	**$ 13,745**	$ 12,216	$ 9,577
Natural gas distribution	**29,444**	28,996	30,656
Pipeline and energy services	**10,516**	9,064	8,896
Exploration and production	**7,445**	8,580	10,621
Construction materials and contracting	**16,241**	19,859	20,495
Construction services	**4,473**	4,411	4,490
Other	**—**	47	43
Intersegment eliminations	**(510)**	(162)	(679)
Total interest expense	**$ 81,354**	$ 83,011	$ 84,099
Income taxes:			
Electric	**$ 7,242**	$ 11,187	$ 8,205
Natural gas distribution	**16,931**	12,171	16,331
Pipeline and energy services	**12,912**	13,933	22,982
Exploration and production	**46,298**	49,034	(187,000)
Construction materials and contracting	**11,227**	13,822	25,940
Construction services	**13,426**	11,456	15,189
Other	**2,238**	10,927	2,261
Total income taxes	**$ 110,274**	$ 122,530	$ (96,092)
Earnings (loss) on common stock:			
Electric	**$ 29,258**	$ 28,908	$ 24,099
Natural gas distribution	**38,398**	36,944	30,796
Pipeline and energy services	**23,082**	23,208	37,845
Exploration and production	**80,282**	85,638	(296,730)
Construction materials and contracting	**26,430**	29,609	47,085
Construction services	**21,627**	17,982	25,589
Other	**6,190**	21,046	7,357
Earnings (loss) on common stock before loss from discontinued operations	**225,267**	243,335	(123,959)
Loss from discontinued operations, net of tax*	**(12,926)**	(3,361)	—
Total earnings (loss) on common stock	**$ 212,341**	$ 239,974	$ (123,959)

	2011	2010	2009
		(In thousands)	
Capital expenditures:			
Electric	**$ 52,072**	$ 85,787	$ 115,240
Natural gas distribution	**70,624**	75,365	43,820
Pipeline and energy services	**45,556**	14,255	70,168
Exploration and production	**272,855**	355,845	183,140
Construction materials and contracting	**52,303**	25,724	26,313
Construction services	**9,711**	14,849	12,814
Other	**18,759**	2,182	3,196

Net proceeds from sale or disposition of property and other	**(40,857)**	(78,761)	(26,679)
Total net capital expenditures	**$ 481,023**	$ 495,246	$ 428,012
Assets:			
Electric**	**$ 672,940**	$ 643,636	$ 569,666
Natural gas distribution**	**1,679,091**	1,632,012	1,588,144
Pipeline and energy services	**526,797**	523,075	538,230
Exploration and production	**1,481,556**	1,342,808	1,137,628
Construction materials and contracting	**1,374,026**	1,382,836	1,449,469
Construction services	**418,519**	387,627	328,895
Other***	**403,196**	391,555	378,920
Total assets	**$6,556,125**	$6,303,549	$5,990,952
Property, plant and equipment:			
Electric**	**$1,068,524**	$1,027,034	$ 941,791
Natural gas distribution**	**1,568,866**	1,508,845	1,456,208
Pipeline and energy services	**719,291**	683,807	675,199
Exploration and production	**2,615,146**	2,356,938	2,028,794
Construction materials and contracting	**1,499,852**	1,486,375	1,514,989
Construction services	**124,796**	122,940	116,236
Other	**49,747**	32,564	33,365
Less accumulated depreciation, depletion and amortization	**3,361,208**	3,103,323	2,872,465
Net property, plant and equipment	**$4,285,014**	$4,115,180	$3,894,117

* Reflected in the Other category.

** Includes allocations of common utility property.

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

Note: The results reflect a $620.0 million ($384.4 million after tax) noncash write-down of natural gas and oil properties in 2009.

Discontinued Operations Discontinued Operations (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011
Arbitration charge related to a guarantee	$ 21.0
Arbitration charge after tax	$ 13.0

Income Taxes (Details 4) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Change in net deferred income tax liability from the preceding table	$ 89,380		
Deferred taxes associated with other comprehensive loss	9,678		
Deferred taxes associated with discontinued operations	8,090		
Other	11,777		
Total Deferred Income Taxes	$ 118,925	$ 66,585	$ (169,764)

Consolidated Statements of Income (USD $) Share data in Thousands, except Per Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	$ 1,343,714,000	$ 1,359,028,000	$ 1,504,269,000
Exploration and production, construction materials and contracting, construction services, and other	2,706,778,000	2,550,667,000	2,672,232,000
Total operating revenues	4,050,492,000	3,909,695,000	4,176,501,000
Operating expenses:			
Fuel and purchased power	64,485,000	63,065,000	65,717,000
Purchased natural gas sold	572,187,000	567,806,000	739,678,000
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	275,866,000	291,524,000	263,869,000
Exploration and production, construction materials and contracting, construction services, and other	2,215,269,000	2,084,377,000	2,143,195,000
Depreciation, depletion and amortization	343,395,000	328,843,000	330,542,000
Taxes, other than income	172,923,000	163,353,000	166,597,000
Noncash write-down of natural gas and oil properties	0	0	620,000,000
Total operating expenses	3,644,125,000	3,498,968,000	4,329,598,000
Operating income (loss)	406,367,000	410,727,000	(153,097,000)
Earnings from equity method investments	4,693,000	30,816,000	8,499,000
Other income	6,520,000	8,018,000	9,331,000
Interest expense	81,354,000	83,011,000	84,099,000
Income (loss) before income taxes	336,226,000	366,550,000	(219,366,000)
Income taxes	110,274,000	122,530,000	(96,092,000)
Income (loss) from continuing operations	225,952,000	244,020,000	(123,274,000)
Income (loss) from discontinued operations, net of tax	(12,926,000) [1]	(3,361,000) [1]	0 [1]
Net income (loss)	213,026,000	240,659,000	(123,274,000)
Dividends on preferred stocks	685,000	685,000	685,000
Earnings (loss) on common stock	$ 212,341,000	$ 239,974,000	$ (123,959,000)
Earnings (loss) per common share - basic:			
Earnings (Loss) Before Discontinued Operations	$ 1.19	$ 1.29	$ (0.67)
Discontinued Operations, Net of Tax	$ (0.07)	$ (0.01)	$ 0.00
Earnings (Loss) Per Common Share - Basic	$ 1.12	$ 1.28	$ (0.67)
Earnings (loss) per common share - diluted:			
Earnings (Loss) Before Discontinued Operations	$ 1.19	$ 1.29	$ (0.67)
Discontinued Operations, Net of Tax	$ (0.07)	$ (0.02)	$ 0.00
Earnings (Loss) Per Common Share - Diluted	$ 1.12	$ 1.27	$ (0.67)
Dividends per common share (in dollars per share)	$ 0.6550	$ 0.6350	$ 0.6225

Weighted average common shares outstanding - basic	188,763	188,137	185,175	[2]
Weighted Average Common Shares Outstanding - Diluted	188,905	188,229	185,175	[2]

[1] Reflected in the Other category.

[2] Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.

Summary of Significant Accounting Policies (Details 2) (USD $)	Dec. 31, 2011	Dec. 31, 2010
Accounting Policies [Abstract]		
Aggregates held for resale	$ 78,518,000	$ 79,894,000
Materials and supplies	61,611,000	57,324,000
Natural gas in storage (current)	36,578,000	34,557,000
Merchandise for resale	32,165,000	30,182,000
Asphalt oil	32,335,000	25,234,000
Other	32,998,000	25,706,000
Inventories and natural gas in storage	274,205,000	252,897,000
Natural gas in storage largely required to maintain pressure levels for normal operating purposes	$ 50,300,000	$ 48,000,000

Supplemental Financial Information Exploration and Production (Details 5) (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended			
	Dec. 31, 2011 Mcfe	Dec. 31, 2010 Mcfe	Dec. 31, 2009 Mcfe	Dec. 31, 2008 Mcfe
Reserve Quantities [Line Items]				
Proved Developed Reserves, Net	476,763,000	494,426,000	482,329,000	
Proved Developed and Undeveloped Reserves, Extensions, Discoveries, and Additions	65,049,000	56,523,000	42,297,000	
Proved Developed and Undeveloped Reserves [Abstract]				
Proved Developed Reserves, Net	476,763,000	494,426,000	482,329,000	
Proved Undeveloped Reserves, Net	109,145,000	151,170,000	171,395,000	
Proved Developed and Undeveloped Reserves, Net	585,908,000	645,596,000	653,724,000	810,371,000
Change in PUD reserve	(42,000,000)			
Amount of PUD reserves converted into proved developed reserves	27,100,000			
Drilling and completion capital	$ 62.9			
Negative revision to PUD reserves	53,600,000			
New PUD reserves	38,700,000			
Future development costs estimated to be spent to develop PUD reserves year one	109.3			
Future development costs estimated to be spent to develop PUD reserves year two	47.8			
Future development costs estimated to be spent to develop PUD reserves year three	$ 13.7			
Natural Gas Reserves [Member]				
Reserve Quantities [Line Items]				
Proved Developed Reserves, Net	303,495	334,911	321,561	
Proved Developed and Undeveloped Reserves, Extensions, Discoveries, and Additions	28,221	36,191	26,882	
Proved Developed and Undeveloped Reserves [Abstract]				
Proved Developed Reserves, Net	303,495	334,911	321,561	
Proved Undeveloped Reserves, Net	76,332	113,486	126,864	
Proved Developed and Undeveloped Reserves, Net	379,827	448,397	448,425	604,282
Oil Reserves [Member]				
Reserve Quantities [Line Items]				
Proved Developed Reserves, Net	28,878	26,586	26,794	
Proved Developed and Undeveloped Reserves, Extensions, Discoveries, and Additions	6,138	3,389	2,569	
Proved Developed and Undeveloped Reserves [Abstract]				
Proved Developed Reserves, Net	28,878	26,586	26,794	
Proved Undeveloped Reserves, Net	5,469	6,281	7,422	
Proved Developed and Undeveloped Reserves, Net	34,347	32,867	34,216	34,348

Consolidated Statements of Common Stockholders' Equity (USD $) In Thousands, except Share data, unless otherwise specified	Total	Common Stock [Member]	Other Paid-in Capital [Member]	Retained Earnings [Member]	Accumulated Other Comprehensive Income (Loss) [Member]	Treasury Stock [Member]
Balance at Dec. 31, 2008	$ 2,746,076	$ 184,208	$ 938,299	$ 1,616,830	$ 10,365	$ (3,626)
Treasury stock (in shares) at Dec. 31, 2008						(538,921)
Balance (in shares) at Dec. 31, 2008		184,208,283				
Comprehensive income:						
Net income	(123,274)		0	(123,274)	0	
Other Comprehensive Income (Loss), Derivatives Qualifying as Hedges, Net of Tax	(51,684)		0	0	(51,684)	
Postretirement liability adjustment	9,918		0	0	9,918	
Foreign currency translation adjustment, net of tax	10,568		0	0	10,568	
Net unrealized gains on available-for-sale investments, net of tax	0					
Total comprehensive income	(154,472)		0	0	0	
Dividends, Preferred Stock, Cash	(685)		0	(685)	0	
Dividends, Common Stock, Cash	(115,832)		0	(115,832)	0	
Adjustments to Additional Paid in Capital, Income Tax Benefit from Share-based Compensation	(117)		(117)	0	0	
Issuance of common stock (in shares)		4,180,982				
Issuance of common stock	81,677	4,181	77,496			
Balance at Dec. 31, 2009	2,556,647	188,389	1,015,678	1,377,039	(20,833)	(3,626)
Treasury stock (in shares) at Dec. 31, 2009						(538,921)
Balance (in shares) at Dec. 31, 2009		188,389,265				
Comprehensive income:						
Net income	240,659		0	240,659	0	
Other Comprehensive Income (Loss), Derivatives Qualifying as Hedges, Net of Tax	673		0	0	673	

Postretirement liability adjustment	(5,730)		0	0	(5,730)	
Foreign currency translation adjustment, net of tax	(5,371)		0	0	(5,371)	
Net unrealized gains on available-for-sale investments, net of tax	0					
Total comprehensive income	230,231		0	0	0	
Dividends, Preferred Stock, Cash	(685)		0	(685)	0	
Dividends, Common Stock, Cash	(119,574)		0	(119,574)	0	
Adjustments to Additional Paid in Capital, Income Tax Benefit from Share-based Compensation	924		924	0	0	
Issuance of common stock (in shares)		512,114				
Issuance of common stock	10,259	512	9,747			
Balance at Dec. 31, 2010	2,677,802	188,901	1,026,349	1,497,439	(31,261)	(3,626)
Treasury stock (in shares) at Dec. 31, 2010	(538,921)					(538,921)
Balance (in shares) at Dec. 31, 2010	188,901,379	188,901,379				
Comprehensive income:						
Net income	213,026		0	213,026	0	
Other Comprehensive Income (Loss), Derivatives Qualifying as Hedges, Net of Tax	7,900		0	0	7,900	
Postretirement liability adjustment	(22,427)		0	0	(22,427)	
Foreign currency translation adjustment, net of tax	(1,295)		0	0	(1,295)	
Net unrealized gains on available-for-sale investments, net of tax	82		0	0	82	
Total comprehensive income	197,286		0	0	0	
Dividends, Preferred Stock, Cash	(685)		0	(685)	0	
Dividends, Common Stock, Cash	(123,657)		0	(123,657)	0	
Adjustments to Additional Paid in Capital, Income Tax Benefit from Share-based Compensation	(909)		(909)	0	0	

Issuance of common stock (in shares)		431,106					
Issuance of common stock	10,730	431	10,299				
Balance at Dec. 31, 2011	$ 2,760,567	$ 189,332	$ 1,035,739	$ 1,586,123	$ (47,001)		$ (3,626)
Treasury stock (in shares) at Dec. 31, 2011	(538,921)						(538,921)
Balance (in shares) at Dec. 31, 2011	189,332,485	189,332,485					

Supplemental Financial Information Exploration and Production (Details 3) (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Results of Operations for Oil and Gas Producing Activities, by Geographic Area [Line Items]			
Results of Operations, Sales or Transfers to Entity's Other Operations	$ 93,713	$ 115,784	$ 101,230
Results of Operations, Sales Revenue to Unaffiliated Enterprises	359,873	318,565	338,425
Results of Operations, Production or Lifting Costs	140,606	127,403	123,148
Results of Operations, Depreciation, Depletion and Amortization, and Valuation Provisions	139,539 [1]	127,266 [1]	126,278 [1]
Results of Operations, Impairment of Oil and Gas Properties	0	0	620,000
Results of Operations, Income before Income Taxes	173,441	179,680	(429,771)
Income Tax Expense (Benefit)	63,655	66,293	(164,216)
Results of Operations, Oil and Gas Producing Activities Net Income (Excluding Corporate Overhead and Interest Costs)	109,786	113,387	(265,555)
Accretion of discount for asset retirement obligations oil and gas	$ 3,600	$ 3,200	$ 2,700

[1] Includes accretion of discount for asset retirement obligations of $3.6 million, $3.2 million and $2.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, as discussed in Note 10.

Derivative Instruments (Details 2) (USD $) In Thousands, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Derivatives, Fair Value [Line Items]		
Derivative Liability Fair Value Gross Liability	$ 18,863	$ 30,911
Derivative Asset, Fair Value, Gross Asset	30,455	19,227
Designated as Hedging Instrument [Member]		
Derivatives, Fair Value [Line Items]		
Derivative Instruments in Hedges, Liabilities, at Fair Value	18,426	21,552
Derivative Instruments in Hedges, Assets, at Fair Value	30,455	19,227
Designated as Hedging Instrument [Member] | Commodity derivative instruments - current assets [Member] | Commodity Contract [Member]		
Derivatives, Fair Value [Line Items]		
Derivative Instruments in Hedges, Assets, at Fair Value	27,687	15,123
Designated as Hedging Instrument [Member] | Other assets noncurrent [Member] | Commodity Contract [Member]		
Derivatives, Fair Value [Line Items]		
Derivative Instruments in Hedges, Assets, at Fair Value	2,768	4,104
Designated as Hedging Instrument [Member] | Commodity derivative instruments - current liabilities [Member] | Commodity Contract [Member]		
Derivatives, Fair Value [Line Items]		
Derivative Instruments in Hedges, Liabilities, at Fair Value	12,727	15,069
Designated as Hedging Instrument [Member] | Other accrued liabilities [Member] | Interest Rate Swap [Member]		
Derivatives, Fair Value [Line Items]		
Derivative Instruments in Hedges, Liabilities, at Fair Value	827	0
Designated as Hedging Instrument [Member] | Other liabilities noncurrent [Member] | Interest Rate Swap [Member]		
Derivatives, Fair Value [Line Items]		
Derivative Instruments in Hedges, Liabilities, at Fair Value	3,935	0
Designated as Hedging Instrument [Member] | Other liabilities noncurrent [Member] | Commodity Contract [Member]		
Derivatives, Fair Value [Line Items]		
Derivative Instruments in Hedges, Liabilities, at Fair Value	937	6,483
Not Designated as Hedging Instrument [Member]		
Derivatives, Fair Value [Line Items]		
Other Derivatives Not Designated as Hedging Instruments Liabilities at Fair Value	437	9,359
Other Derivatives Not Designated as Hedging Instruments Assets at Fair Value	0	0
Not Designated as Hedging Instrument [Member] | Commodity derivative instruments - current assets [Member] | Commodity Contract [Member]		
Derivatives, Fair Value [Line Items]		
Other Derivatives Not Designated as Hedging Instruments Assets at Fair Value	0	0

Not Designated as Hedging Instrument [Member] | Other assets noncurrent [Member] | Commodity Contract [Member]		
Derivatives, Fair Value [Line Items]		
Other Derivatives Not Designated as Hedging Instruments Assets at Fair Value	0	0
Not Designated as Hedging Instrument [Member] | Commodity derivative instruments - current liabilities [Member] | Commodity Contract [Member]		
Derivatives, Fair Value [Line Items]		
Other Derivatives Not Designated as Hedging Instruments Liabilities at Fair Value	437	9,359
Not Designated as Hedging Instrument [Member] | Other liabilities noncurrent [Member] | Commodity Contract [Member]		
Derivatives, Fair Value [Line Items]		
Other Derivatives Not Designated as Hedging Instruments Liabilities at Fair Value	$ 0	$ 0

Schedule I-Condensed Financial Information of Registrant (Details) (USD $)	3 Months Ended								12 Months Ended			
	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2010	Jun. 30, 2010	Mar. 31, 2010	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009	Dec. 31, 2008
Condensed Financial Statements, Captions [Line Items]												
Operating revenues	$ 1,065,749,000	$ 1,152,181,000	$ 930,757,000	$ 901,805,000	$ 1,042,551,000	$ 1,125,923,000	$ 906,444,000	$ 834,777,000	$ 4,050,492,000	$ 3,909,695,000	$ 4,176,501,000	
Operating expenses	939,172,000	1,032,760,000	848,454,000	823,739,000	912,377,000	1,016,961,000 [1]	817,782,000	751,848,000	3,644,125,000	3,498,968,000	4,329,598,000	
Operating income (loss)	126,577,000	119,421,000	82,303,000	78,066,000	130,174,000	108,962,000 [1]	88,662,000	82,929,000	406,367,000	410,727,000	(153,097,000)	
Other income									6,520,000	8,018,000	9,331,000	
Interest expense									81,354,000	83,011,000	84,099,000	
Income taxes									110,274,000	122,530,000	(96,092,000)	
Net income (loss)	61,008,000 [2]	63,974,000	45,067,000	42,977,000	88,939,000 [3]	61,010,000 [1]	48,938,000	41,772,000	213,026,000	240,659,000	(123,274,000)	
Dividends on preferred stocks									685,000	685,000	685,000	
Earnings on common stock									212,341,000	239,974,000	(123,959,000)	
Current assets:												
Cash and cash equivalents	162,772,000				222,074,000				162,772,000	222,074,000	175,114,000	
Receivables, net	646,251,000				583,743,000				646,251,000	583,743,000		
Inventories	274,205,000				252,897,000				274,205,000	252,897,000		
Deferred income taxes	40,407,000				32,890,000				40,407,000	32,890,000		
Prepayments and other current assets	43,316,000				60,441,000				43,316,000	60,441,000		
Total current assets	1,194,638,000				1,167,168,000				1,194,638,000	1,167,168,000		
Investments	109,424,000				103,661,000				109,424,000	103,661,000		
Property, plant and equipment	7,646,222,000				7,218,503,000				7,646,222,000	7,218,503,000		
Less accumulated depreciation, depletion and amortization	3,361,208,000				3,103,323,000				3,361,208,000	3,103,323,000	2,872,465,000	
Net property, plant and equipment	4,285,014,000				4,115,180,000				4,285,014,000	4,115,180,000	3,894,117,000	
Deferred charges and other assets: [Abstract]												
Goodwill	634,931,000 [4]				634,633,000 [4]				634,931,000 [4]	634,633,000 [4]	629,463,000 [4]	
Other	311,275,000				257,636,000				311,275,000	257,636,000		
Total deferred charges and other assets	967,049,000				917,540,000				967,049,000	917,540,000		
Total assets	6,556,125,000				6,303,549,000				6,556,125,000	6,303,549,000	5,990,952,000	
Current liabilities:												
Short-term borrowings	0				20,000,000				0	20,000,000		
Long-term debt due within one year	139,267,000				72,797,000				139,267,000	72,797,000		
Accounts payable	337,228,000				301,132,000				337,228,000	301,132,000		
Taxes payable	70,176,000				56,186,000				70,176,000	56,186,000		
Dividends payable	31,794,000				30,773,000				31,794,000	30,773,000		
Accrued Compensation	47,804,000				40,121,000				47,804,000	40,121,000		
Other accrued liabilities	259,320,000				222,639,000				259,320,000	222,639,000		
Total current liabilities	898,753,000				768,076,000				898,753,000	768,076,000		
Long-term debt	1,285,411,000				1,433,955,000				1,285,411,000	1,433,955,000		
Deferred credits and other liabilities:												
Deferred income taxes	769,166,000				672,269,000				769,166,000	672,269,000		
Other liabilities	827,228,000				736,447,000				827,228,000	736,447,000		
Total deferred credits and other liabilities	1,596,394,000				1,408,716,000				1,596,394,000	1,408,716,000		
Stockholders' equity:												
Preferred stocks	15,000,000				15,000,000				15,000,000	15,000,000		
Common stockholders' equity:												
Common stock shares authorized - 500,000,000 - issued - $1.00 par value, 189,332,485 shares at December 31, 2011 and 188,901,379 shares at December 31, 2010	189,332,000				188,901,000				189,332,000	188,901,000		
Other paid-in capital	1,035,739,000				1,026,349,000				1,035,739,000	1,026,349,000		
Retained earnings	1,586,123,000				1,497,439,000				1,586,123,000	1,497,439,000		
Accumulated other comprehensive loss	(47,001,000)				(31,261,000)				(47,001,000)	(31,261,000)	(20,833,000)	
Treasury stock at cost - 538,921 shares	(3,626,000)				(3,626,000)				(3,626,000)	(3,626,000)		
Total common stockholders' equity	2,760,567,000				2,677,802,000				2,760,567,000	2,677,802,000	2,556,647,000	2,746,076,000
Total stockholders' equity	2,775,567,000				2,692,802,000				2,775,567,000	2,692,802,000		
Total liabilities and stockholders' equity	6,556,125,000				6,303,549,000				6,556,125,000	6,303,549,000		
Net cash provided by operating activities									626,648,000	551,633,000	846,686,000	
Investing activities:												
Capital expenditures									(497,000,000)	(449,282,000)	(448,675,000)	
Net proceeds from sale or disposition of property and other									40,107,000	76,386,000	26,679,000	
Investments									(10,302,000)	704,000	(3,740,000)	

Net cash used in investing activities					(464,545,000)	(407,944,000)	(432,146,000)
Financing activities:							
Issuance of short-term borrowings					0	20,000,000	10,300,000
Repayment of short-term borrowings					(20,000,000)	(10,300,000)	(105,100,000)
Issuance of long-term debt					300,000	20,200,000	145,000,000
Repayment of long-term debt					(85,151,000)	(13,668,000)	(292,907,000)
Proceeds from issuance of common stock					5,744,000	4,972,000	65,207,000
Dividends paid					(123,323,000)	(119,157,000)	(115,023,000)
Excess tax benefit on stock-based compensation					1,239,000	1,186,000	601,000
Net cash provided by (used in) financing activities					(221,191,000)	(96,767,000)	(291,922,000)
Increase (decrease) in cash and cash equivalents					(59,302,000)	46,960,000	123,400,000
Cash and cash equivalents - beginning of year		222,074,000		175,114,000	222,074,000	175,114,000	51,714,000
Cash and cash equivalents - end of year	162,772,000		222,074,000		162,772,000	222,074,000	175,114,000
MDU Resources Group, Inc [Member]							
Condensed Financial Statements, Captions [Line Items]							
Operating revenues					518,268,000	503,658,000	514,519,000
Operating expenses					450,579,000	431,293,000	458,130,000
Operating income (loss)					67,689,000	72,365,000	56,389,000
Other income					2,710,000	5,734,000	6,588,000
Interest expense					18,660,000	16,664,000	13,996,000
Income before income taxes					51,739,000	61,435,000	48,981,000
Income taxes					10,476,000	17,983,000	13,279,000
Equity in earnings of subsidiaries					171,763,000	197,207,000	(158,976,000)
Net income (loss)					213,026,000	240,659,000	(123,274,000)
Dividends on preferred stocks					685,000	685,000	685,000
Earnings on common stock					212,341,000	239,974,000	(123,959,000)
Current assets:							
Cash and cash equivalents	6,900,000		6,275,000		6,900,000	6,275,000	30,103,000
Receivables, net	67,761,000		76,757,000		67,761,000	76,757,000	
Accounts receivable from subsidiaries	28,734,000		27,837,000		28,734,000	27,837,000	
Inventories	42,596,000		34,583,000		42,596,000	34,583,000	
Deferred income taxes	2,000		0		2,000	0	
Prepayments and other current assets	12,154,000		15,473,000		12,154,000	15,473,000	
Total current assets	158,147,000		160,925,000		158,147,000	160,925,000	
Investments	47,835,000		48,038,000		47,835,000	48,038,000	
Investment in subsidiaries	2,402,891,000		2,336,133,000		2,402,891,000	2,336,133,000	
Property, plant and equipment	1,453,089,000		1,388,128,000		1,453,089,000	1,388,128,000	
Less accumulated depreciation, depletion and amortization	605,510,000		583,447,000		605,510,000	583,447,000	
Net property, plant and equipment	847,579,000		804,681,000		847,579,000	804,681,000	
Deferred charges and other assets: [Abstract]							
Goodwill	4,812,000		4,812,000		4,812,000	4,812,000	
Other	166,732,000		119,081,000		166,732,000	119,081,000	
Total deferred charges and other assets	171,544,000		123,893,000		171,544,000	123,893,000	
Total assets	3,627,996,000		3,473,670,000		3,627,996,000	3,473,670,000	
Current liabilities:							
Short-term borrowings	0		20,000,000		0	20,000,000	
Long-term debt due within one year	107,000		107,000		107,000	107,000	
Accounts payable	37,986,000		36,235,000		37,986,000	36,235,000	
Accounts payable to subsidiaries	4,868,000		9,445,000		4,868,000	9,445,000	
Taxes payable	18,304,000		8,104,000		18,304,000	8,104,000	
Deferred income taxes	0		469,000		0	469,000	
Dividends payable	31,794,000		30,773,000		31,794,000	30,773,000	
Accrued Compensation	10,173,000		11,540,000		10,173,000	11,540,000	
Other accrued liabilities	27,064,000		26,002,000		27,064,000	26,002,000	
Total current liabilities	130,296,000		142,675,000		130,296,000	142,675,000	
Long-term debt	280,781,000		280,889,000		280,781,000	280,889,000	
Deferred credits and other liabilities:							
Deferred income taxes	137,751,000		103,725,000		137,751,000	103,725,000	
Other liabilities	303,601,000		253,579,000		303,601,000	253,579,000	
Total deferred credits and other liabilities	441,352,000		357,304,000		441,352,000	357,304,000	
Stockholders' equity:							
Preferred stocks	15,000,000		15,000,000		15,000,000	15,000,000	

Common stockholders' equity:							
Common stock shares authorized - 500,000,000 - issued - $1.00 par value, 189,332,485 shares at December 31, 2011 and 188,901,379 shares at December 31, 2010	189,332,000		188,901,000		189,332,000	188,901,000	
Other paid-in capital	1,035,739,000		1,026,349,000		1,035,739,000	1,026,349,000	
Retained earnings	1,586,123,000		1,497,439,000		1,586,123,000	1,497,439,000	
Accumulated other comprehensive loss	(47,001,000)		(31,261,000)		(47,001,000)	(31,261,000)	
Treasury stock at cost - 538,921 shares	(3,626,000)		(3,626,000)		(3,626,000)	(3,626,000)	
Total common stockholders' equity	2,760,567,000		2,677,802,000		2,760,567,000	2,677,802,000	
Total stockholders' equity	2,775,567,000		2,692,802,000		2,775,567,000	2,692,802,000	
Total liabilities and stockholders' equity	3,627,996,000		3,473,670,000		3,627,996,000	3,473,670,000	
Net cash provided by operating activities					217,514,000	185,887,000	209,128,000
Investing activities:							
Capital expenditures					(74,580,000)	(114,045,000)	(120,352,000)
Net proceeds from sale or disposition of property and other					720,000	625,000	1,039,000
Investments in and advances to subsidiaries					(5,701,000)	(1,636,000)	0
Investments From and Advances From Subsidiaries					0	0	2,916,000
Disposition of investments in subsidiaries					0	0	20,000,000
Investments					0	(742,000)	(637,000)
Net cash used in investing activities					(79,561,000)	(115,798,000)	(97,034,000)
Financing activities:							
Issuance of short-term borrowings					0	20,000,000	0
Repayment of short-term borrowings					(20,000,000)	0	0
Issuance of long-term debt					0	0	50,000,000
Repayment of long-term debt					(107,000)	(107,000)	(85,104,000)
Proceeds from issuance of common stock					5,744,000	4,972,000	65,207,000
Dividends paid					(123,323,000)	(119,157,000)	(115,023,000)
Excess tax benefit on stock-based compensation					358,000	375,000	264,000
Net cash provided by (used in) financing activities					(137,328,000)	(93,917,000)	(84,656,000)
Increase (decrease) in cash and cash equivalents					625,000	(23,828,000)	27,438,000
Cash and cash equivalents - beginning of year		6,275,000		30,103,000	6,275,000	30,103,000	2,665,000
Cash and cash equivalents - end of year	6,900,000		6,275,000		6,900,000	6,275,000	30,103,000
Debt Disclosure [Abstract]							
Long-term Debt	280,900,000				280,900,000		
Long-term Debt, Maturities, Repayments of Principal in Next Twelve Months	100,000				100,000		
2012	100,000				100,000		
2013	100,000				100,000		
2014	100,000				100,000		
2015	100,000				100,000		
2016	50,000,000				50,000,000		
Thereafter 2016	230,500,000				230,500,000		
Cash Dividends Paid to Parent Company [Abstract]							
Cash Dividends Paid to Parent Company by Consolidated Subsidiaries					$ 96,100,000	$ 96,400,000	$ 116,300,000

[1] 2010 reflects a natural gas gathering arbitration charge of $16.5 million (after tax). For more information, see Note 19.

[2] 2011 reflects an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract. For more information, see Note 19.

[3] 2010 reflects a $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines. For more information, see Note 4.

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

Debt (Tables)	12 Months Ended Dec. 31, 2011
Debt Disclosure [Abstract]	
Outstanding Credit Facilities	The following table summarizes the outstanding credit facilities of the Company and its subsidiaries:

Company	Facility		Facility Limit		Amount Outstanding at December 31, 2011		Amount Outstanding at December 31, 2010		Letters of Credit at December 31, 2011	Expiration Date
							(Dollars in millions)			
MDU Resources Group, Inc.	Commercial paper/ Revolving credit agreement	(a)	$ 100.0	$	— (h)	$	20.0 (b)	$	—	5/26/15
Cascade Natural Gas Corporation	Revolving credit agreement		$ 50.0 (c)	$	—	$	—	$	1.9 (d)	12/28/12 (e)
Intermountain Gas Company	Revolving credit agreement		$ 65.0 (f)	$	8.1	$	20.2	$	—	8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement	(g)	$ 400.0	$	— (h)	$	— (h)	$	21.6 (d)	12/13/12

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 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 that was classified as short-term borrowings because the revolving credit agreement expired within one year.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.
(e) Provisions allow for an extension of up to two years upon consent of the banks.
(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(g) 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.
(h) Amount outstanding under commercial paper program.

Long Term Debt Outstanding

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

	2011	2010
	(In thousands)	
Senior Notes at a weighted average rate of 6.01%, due on dates ranging from May 15, 2012 to March 8, 2037	**$ 1,287,576**	$ 1,358,848
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	**40,469**	41,189
Credit agreements at a weighted average rate of 2.98%, due on dates ranging from September 30, 2012 to November 30, 2038	**15,633**	25,715
Total long-term debt	**1,424,678**	1,506,752
Less current maturities	**139,267**	72,797
Net long-term debt	**$ 1,285,411**	$ 1,433,955

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2011, aggregate $139.3 million in 2012; $267.3 million in 2013; $9.3 million in 2014; $266.4 million in 2015; $288.4 million in 2016 and $454.0 million thereafter.

Asset Retirement Obligations (Details) (USD $)	12 Months Ended	
	Dec. 31, 2011	Dec. 31, 2010
Asset retirement obligation [Roll Forward]		
Balance, beginning of period	$ 95,970,000	$ 76,359,000
Liabilities incurred	3,870,000	8,608,000
Liabilities acquired	0	5,272,000
Asset Retirement Obligation, Liabilities Settled	(10,418,000)	(10,740,000)
Accretion expense	4,466,000	3,588,000
Revisions in estimates	3,921,000	12,621,000
Other	342,000	262,000
Balance, end of period	98,151,000	95,970,000
Fair value of assets legally restricted for purposes of settling asset retirement obligations	$ 5,700,000	$ 5,700,000

Employee Benefit Plans

12 Months Ended Dec. 31, 2011

Compensation and Retirement Disclosure [Abstract]

Employee Benefit Plans

Employee Benefit Plans

Pension and other postretirement benefit plans

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

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011, all benefit and service accruals for an additional union plan were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

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

Changes in benefit obligation and plan assets for the years ended December 31, 2011 and 2010, and amounts recognized in the Consolidated Balance Sheets at December 31, 2011 and 2010, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 388,589**	$ 352,915	**$ 91,286**	$ 88,151
Service cost	**2,252**	2,889	**1,443**	1,357
Interest cost	**19,500**	19,761	**4,700**	4,817
Plan participants' contributions	**—**	—	**2,644**	2,500
Amendments	**—**	353	**—**	121
Actuarial loss	**62,722**	34,687	**17,940**	3,228
Curtailment gain	**(13,939)**	—	**—**	—
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Benefit obligation at end of year	**435,618**	388,589	**110,689**	91,286
Change in net plan assets:				
Fair value of plan assets at beginning of year	**277,598**	255,327	**70,610**	66,984
Actual gain (loss) on plan assets	**(4,718)**	37,853	**(872)**	7,278
Employer contribution	**28,626**	6,434	**3,027**	2,736
Plan participants' contributions	**—**	—	**2,644**	2,500
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Fair value of net plan assets at end of year	**278,000**	277,598	**68,085**	70,610
Funded status - under	**$ (157,618)**	$ (110,991)	**$ (42,604)**	$ (20,676)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	**$ —**	$ —	**$ (550)**	$ (525)
Other liabilities (noncurrent)	**(157,618)**	(110,991)	**(42,054)**	(20,151)
Net amount recognized	**$ (157,618)**	$ (110,991)	**$ (42,604)**	$ (20,676)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 189,494**	$ 117,840	**$ 43,861**	$ 20,751
Prior service cost (credit)	**(632)**	631	**(8,615)**	(11,292)
Transition obligation	**—**	—	**2,128**	4,253
Total	**$ 188,862**	$ 118,471	**$ 37,374**	$ 13,712

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 are amortized on a straight-line basis over the expected average remaining service lives of active participants for non-frozen plans and over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation is amortized over a 20-year period ending 2012.

The accumulated benefit obligation for the defined benefit pension plans reflected previously was $435.6 million and $374.5 million at December 31, 2011 and 2010, 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:

	2011	2010
	(In thousands)	
Projected benefit obligation	**$ 435,618**	$ 388,589
Accumulated benefit obligation	**$ 435,618**	$ 374,538
Fair value of plan assets	**$ 278,000**	$ 277,598

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		
	2011	2010	2009	**2011**	2010	2009
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	**$ 2,252**	$ 2,889	$ 8,127	**$ 1,443**	$ 1,357	$ 2,206
Interest cost	**19,500**	19,761	21,919	**4,700**	4,817	5,465
Expected return on assets	**(22,809)**	(23,643)	(25,062)	**(5,051)**	(5,512)	(5,471)
Amortization of prior service cost (credit)	**45**	152	605	**(2,677)**	(3,303)	(2,756)
Recognized net actuarial loss	**4,656**	2,622	2,096	**753**	845	970
Curtailment loss	**1,218**	—	1,650	**—**	—	—
Amortization of net transition obligation	**—**	—	—	**2,125**	2,125	2,125
Net periodic benefit cost, including amount capitalized	**4,862**	1,781	9,335	**1,293**	329	2,539
Less amount capitalized	**1,196**	791	1,127	**(50)**	(92)	330
Net periodic benefit cost	**3,666**	990	8,208	**1,343**	421	2,209
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**76,310**	20,477	(29,000)	**23,863**	1,462	(2,314)
Prior service cost (credit)	**—**	353	—	**—**	121	(9,321)
Amortization of actuarial loss	**(4,656)**	(2,622)	(2,096)	**(753)**	(845)	(970)
Amortization of prior service (cost) credit	**(1,263)**	(152)	(2,255)	**2,677**	3,303	2,756
Amortization of net transition obligation	**—**	—	—	**(2,125)**	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	**70,391**	18,056	(33,351)	**23,662**	1,916	(11,974)

Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	**$**	**74,057**	$	19,046	$	(25,143)	**$**	**25,005**	$	2,337	$	(9,765)

The estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $7.6 million and $85,000, 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 2012 are $1.9 million, $1.1 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	
	2011	2010	**2011**	2010
Discount rate	**4.16%**	5.26%	**4.13%**	5.21%
Expected return on plan assets	**7.75%**	7.75%	**6.75%**	6.75%
Rate of compensation increase	**N/A**	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	
	2011	2010	**2011**	2010
Discount rate	**5.26%**	5.75%	**5.21%**	5.75%
Expected return on plan assets	**7.75%**	8.25%	**6.75%**	7.25%
Rate of compensation increase	**% / 4.00N/A ***	4.00%	**4.00%**	4.00%

* Effective June 30, 2011, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.

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

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

	2011			2010		
Health care trend rate assumed for next year	**6.0%**	**-**	**8.0%**	6.0%	-	8.5%
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, 2011:

		1 Percentage Point Increase		1 Percentage Point Decrease
		(In thousands)		
Effect on total of service and interest cost components	$	171	$	(822)
Effect on postretirement benefit obligation	$	3,175	$	(10,946)

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 futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

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

	Fair Value Measurements at December 31, 2011, 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, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 2,256	$ 17,534	$ —	$ 19,790
Equity securities:				
U.S. companies	99,315	—	—	99,315
International companies	35,353	—	—	35,353
Collective and mutual funds (a)	43,214	15,541	—	58,755
Corporate bonds	—	23,579	289	23,868
Mortgage-backed securities	—	22,987	—	22,987
Municipal bonds	—	9,290	—	9,290
U.S. Treasury securities	—	8,642	—	8,642
Total assets measured at fair value	$ 180,138	$ 97,573	$ 289	$ 278,000

(a) Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.

	Fair Value Measurements at December 31, 2010, 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, 2010
	(In thousands)			
Assets:				
Cash equivalents	$ 4,663	$ 8,699	$ —	$ 13,362
Equity securities:				
U.S. companies	102,944	—	—	102,944
International companies	40,017	—	—	40,017
Collective and mutual funds (a)	45,410	17,701	—	63,111
Collateral held on loaned securities (b)	—	23,148	694	23,842
Corporate bonds	—	23,014	—	23,014
Mortgage-backed securities	—	19,478	—	19,478
U.S. Treasury securities	—	9,239	—	9,239
Municipal bonds	—	8,285	—	8,285
Total assets measured at fair value	193,034	109,564	694	303,292
Liabilities:				
Obligation for collateral received	25,694	—	—	25,694
Net assets measured at fair value	$ 167,340	$ 109,564	$ 694	$ 277,598

(a) Collective and mutual funds invest approximately 28 percent in common stock of mid-cap U.S. companies, 24 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 11 percent in mortgage-backed securities, 10 percent in corporate bonds, 8 percent in foreign fixed-income investments and 6 percent in common stock of small-cap U.S. companies.
(b) This class includes collateral held at December 31, 2010, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, mutual funds and commercial paper.

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, 2011:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
	(In thousands)		
Balance at beginning of year	$ —	$ 694	$ 694
Total realized/unrealized losses	(2)	(259)	(261)
Purchases, issuances and settlements (net)	291	(435)	(144)
Balance at end of year	$ 289	$ —	$ 289

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, 2010:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Collateral Held on Loaned Securities
	(In thousands)
Balance at beginning of year	$ 937
Total realized/unrealized losses	189
Purchases, issuances and settlements (net)	(432)
Balance at end of year	$ 694

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

	Fair Value Measurements at December 31, 2011, 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, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 59	$ 1,836	$ —	$ 1,895
Equity securities:				
U.S. companies	2,098	—	—	2,098
International companies	262	—	—	262
Insurance investment contract*	—	63,830	—	63,830
Total assets measured at fair value	$ 2,419	$ 65,666	$ —	$ 68,085

* The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.

Fair Value Measurements
at December 31, 2010, 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, 2010
		(In thousands)		
Assets:				
Cash equivalents	$ 53	$ 1,274	$ —	$ 1,327
Equity securities:				
U.S. companies	2,791	—	—	2,791
International companies	353	—	—	353
Insurance investment contract*	—	66,139	—	66,139
Total assets measured at fair value	$ 3,197	$ 67,413	$ —	$ 70,610

* The insurance investment contract invests approximately 53 percent in common stock of large-cap U.S. companies, 21 percent in corporate bonds, 12 percent in mortgage-backed securities and 14 percent in other investments.

The Company expects to contribute approximately $20.2 million to its defined benefit pension plans and approximately $4.0 million to its postretirement benefit plans in 2012.

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2012	$ 22,426	$ 6,892	$ 618
2013	22,811	7,062	656
2014	23,082	7,188	694
2015	23,508	7,298	730
2016	23,893	7,371	766
2017 - 2021	127,895	37,682	4,322

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of $76.9 million and $77.5 million at December 31, 2011 and 2010, respectively, consisting of equity securities of $38.4 million and $39.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $31.8 million and $30.7 million, respectively, and other investments of $6.7 million and $7.3 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $8.1 million, $7.8 million and $8.8 million in 2011, 2010 and 2009, respectively. The total projected benefit obligation for these plans was $113.8 million and $99.4 million at December 31, 2011 and 2010, respectively. The accumulated benefit obligation for these plans was $105.7 million and $93.2 million at December 31, 2011 and 2010, respectively. A weighted average discount rate of 4 percent and 5.11 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4 percent at December 31, 2011 and 2010, were used to determine benefit obligations. A discount rate of 5.11 percent and 5.75 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4 percent at December 31, 2011 and 2010, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $5.2 million in 2012; $5.9 million in 2013; $5.8 million in 2014; $6.9 million in 2015; $6.8 million in 2016 and $38.3 million for the years 2017 through 2021.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $27.1 million in 2011, $24.4 million in 2010 and $20.5 million in 2009.

Multiemployer plans

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

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

The Company's participation in these plans for the annual period ended December 31, 2011, is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2011 and 2010 is for the plan's year-end at December 31, 2010, and December 31, 2009, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded. From 2009 to 2010 and 2010 to 2011, contributions by the Company to multiemployer defined benefit pension plans decreased as a result of a reduction in covered employees corresponding to a decline in overall business.

		Pension Protection Act Zone Status		FIP/RP Status	Contributions				Expiration Date of Collective
Pension Fund	EIN/Pension Plan Number	2011	2010	Pending/ Implemented	**2011**	2010	2009	Surcharge Imposed	Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green	Green	No	**$ 2,700**	$ 1,933	$ 1,627	No	12/31/2012
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**1,469**	1,277	594	No	*
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2011	Red as of 6/30/2010	Implemented	**1,331**	1,569	1,197	No	*
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2011	Red as of 2/28/2010	Implemented	**722**	781	641	No	8/31/2012
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2011	Yellow as of 5/31/2010	Implemented	**628**	413	325	No	6/30/2012*
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**776**	679	469	No	*
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**4,841**	4,826	5,462	No	5/31/2014*
OE Pension Trust Fund	94-6090764-001	Yellow	Yellow	Implemented	**1,367**	1,035	1,061	No	3/31/2016*
Other funds					**15,324**	17,763	21,103		
Total contributions					**$ 29,158**	$ 30,276	$ 32,479		

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

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

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Defined Benefit Pension Plan of AGC-IUOE Local 701 Pension Trust Fund	2010 and 2009
Edison Pension Plan	2010 and 2009
Eighth District Electrical Pension Fund	2010 and 2009
IBEW Local 38 Pension Plan	2010 and 2009
IBEW Local No. 82 Pension Plan	2010 and 2009
IBEW Local Union No. 357 Pension Plan A	2010 and 2009
IBEW Local 648 Pension Plan	2010 and 2009
Idaho Plumbers and Pipefitters Pension Plan	2010 and 2009
Laborers AGC Pension Trust of Montana	2009
Local Union No. 124 IBEW Pension Trust Fund	2010 and 2009
Local Union 212 IBEW Pension Trust Fund	2010 and 2009
Minnesota Teamsters Constr Division Pension Fund	2010 and 2009
Operating Engineers Local 800 and Wyoming Contractors Association, Inc. Pension Plan for Wyoming	2010 and 2009
Plumbers & Pipefitters Local 162 Pension Fund	2010 and 2009
Southwest Marine Pension Trust	2009

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $24.0 million, $24.7 million and $28.9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Amounts contributed in 2011, 2010 and 2009 to defined contribution multiemployer plans were $15.3 million, $15.4 million and $16.4 million, respectively.

Asset Retirement Obligations (Tables)	12 Months Ended Dec. 31, 2011
Asset Retirement Obligation [Abstract]	
Reconciliation of the Company's Asset Retirement Obligation	A reconciliation of the Company's liability, which is included in other liabilities, for the years ended December 31 was as follows:

	2011	2010
	(In thousands)	
Balance at beginning of year	**$ 95,970**	$ 76,359
Liabilities incurred	**3,870**	8,608
Liabilities acquired	**—**	5,272
Liabilities settled	**(10,418)**	(10,740)
Accretion expense	**4,466**	3,588
Revisions in estimates	**3,921**	12,621
Other	**342**	262
Balance at end of year	**$ 98,151**	$ 95,970

Supplemental Financial Information Exploration and Production (Details 7) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves [Line Items]			
Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, Beginning Balance	$ 896,100	$ 658,800	$ 969,800
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(301,500)	(270,000)	(200,900)
Net Increase (Decrease) in Sales and Transfer Prices and Production Costs	82,300	362,400	(364,800)
Extensions Discoveries Less Related Costs	226,300	130,500	70,500
Improved recovery, net of production costs	0	0	0
Increase Due to Purchases of Minerals in Place	9,500	99,800	0
Decrease Due to Sales of Minerals in Place	0	(500)	(1,100)
Changes in Estimated Future Development Costs	51,100	34,100	43,600
Previously Estimated Development Costs Incurred During Period	56,300	43,100	46,400
Accretion of Discount	105,000	76,500	115,900
Changes in Future Income Tax Expense Estimates on Future Cash Flows Related to Proved Oil and Gas Reserves	(55,800)	(103,300)	142,800
Revisions of Previous Quantity Estimates	(92,900)	(132,000)	(155,500)
Standardized Measure of Discounted Future Net Cash Flow of Proved Oil and Gas Reserves, Other	2,400	(3,300)	(7,900)
Standardized Measure of Discounted Future Net Cash Flow of Proved Oil and Gas Reserves, Period Increase (Decrease)	82,700	237,300	(311,000)
Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, Ending Balance	$ 978,800	$ 896,100	$ 658,800

Regulatory Matters and Revenues Subject to Refund	12 Months Ended Dec. 31, 2011
Regulated Operations [Abstract]	
Regulatory Matters and Revenues Subject to Refund	Regulatory Matters and Revenues Subject to Refund On May 20, 2011, Montana-Dakota filed an application with the NDPSC requesting advance determination of prudence that the addition of the air quality control system at the Big Stone Station, to comply with the Clean Air Act and the South Dakota Regional Haze Implementation Plan, is reasonable and prudent. A hearing was held on November 29, 2011. On January 9, 2012, Montana-Dakota, Otter Tail Corporation and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the air quality control system is prudent. An order is expected in the first quarter of 2012. On July 7, 2011, Montana-Dakota filed for an advance determination of prudence with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities projected to be in service in 2015. The turbine will be located on company-owned property that is adjacent to Montana-Dakota's Heskett Generating Station near Mandan, North Dakota, and would be used to meet the capacity requirements of Montana-Dakota's integrated electric system service customers. The capacity will be a partial replacement for third party contract capacity expiring in 2015. Project cost is estimated to be $85.6 million. A hearing was held on January 10, 2012. On January 18, 2012, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the natural gas turbine is prudent and a certificate of need should be approved. An order is expected in the first quarter of 2012. On November 15, 2011, the MNPUC issued a Notice of Investigation; Opportunity to Respond and Comment to investigate whether Great Plains' rates are unreasonable and whether Great Plains should be ordered to initiate a general rate proceeding as Great Plains has earned in excess of its authorized return and the excess earnings are likely to continue into the future. On December 2, 2011, Great Plains responded to the MNPUC's Notice. On January 30, 2012, the MNPUC issued an order that found that the reasonableness of Great Plains' rates had not been resolved to the MNPUC's satisfaction and requires Great Plains to initiate a rate proceeding within 180 days of the order. In addition, the MNPUC encouraged Great Plains, the Minnesota Department of Commerce and any other interested parties to enter into settlement discussions with the requirement that the interested parties file a report on the status of settlement discussions within 60 days of the order.

Stock-Based Compensation Stock-Based Compensation (Details) (USD $)	12 Months Ended		
	Dec. 31, 2011 Y	Dec. 31, 2010	Dec. 31, 2009
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]			
Share-based Compensation Arrangement by Share-based Payment Award, Number of Shares Available for Grant	6,300,000		
Allocated Share-based Compensation Expense	$ 3,500,000	$ 3,400,000	$ 3,400,000
Income taxes on share - based compensation expense	2,200,000	2,100,000	2,200,000
Share Based Compensation Nonvested Awards Total Compensation Cost Not Yet Recognized	5,500,000		
Share-based Compensation, Nonvested Awards, Total Compensation Cost Not yet Recognized, Period for Recognition	1.6		
Stock Options [Member]			
Share-based Compensation Arrangement by Share-based Payment Award, Options, Outstanding [Roll Forward]			
Share-based Compensation Arrangement by Share-based Payment Award, Options, Outstanding, Number	440,984		
Share-based Compensation Arrangement by Share-based Payment Award, Options, Outstanding, Weighted Average Exercise Price Beginning of Period	$ 13.34		
Share-based Compensation Arrangement by Share-based Payment Award, Options, Forfeitures in Period	(3,893)		
Share-based Compensation Arrangement by Share-based Payment Award, Options, Forfeitures in Period, Weighted Average Exercise Price	$ 13.22		
Share-based Compensation Arrangement by Share-based Payment Award, Options, Exercises in Period	(430,341)		
Share-based Compensation Arrangement by Share-based Payment Award, Options, Exercises in Period, Weighted Average Exercise Price	$ 13.34		
Share-based Compensation Arrangement by Share-based Payment Award, Options, Outstanding, Number	6,750	440,984	
Share-based Compensation Arrangement by Share-based Payment Award, Options, Outstanding, Weighted Average Exercise Price End of Period	$ 13.03	$ 13.34	
Share-based Compensation Arrangement by Share-based Payment Award, Options, Exercisable, Number	6,750		
Share-based Compensation Arrangement by Share-based Payment Award, Options, Exercisable, Weighted Average Exercise Price	$ 13.03		
Share-based Compensation Arrangement by Share-based Payment Award, Options, Outstanding, Intrinsic Value	57,000		
Remaining Contractual Life	six months		
Proceeds from Stock Options Exercised	5,700,000	5,000,000	2,100,000
Share-based Compensation Arrangement by Share-based Payment Award, Options, Exercises in Period, Total Intrinsic Value	3,300,000	2,600,000	1,300,000

Employee Stock Options [Member]			
Share-based Compensation Arrangement by Share-based Payment Award, Options, Additional Disclosures [Abstract]			
Share-based Compensation Arrangement by Share-based Payment Award, Expiration Date	ten years		
Share-based Compensation Arrangement by Share-based Payment Award, Award Vesting Period	three years		
Key Employee Stock Options [Member]			
Share-based Compensation Arrangement by Share-based Payment Award, Options, Additional Disclosures [Abstract]			
Share-based Compensation Arrangement by Share-based Payment Award, Expiration Date	ten years		
Share-based Compensation Arrangement by Share-based Payment Award, Award Vesting Period	nine years		
Director Stock Options [Member]			
Share-based Compensation Arrangement by Share-based Payment Award, Options, Additional Disclosures [Abstract]			
Share-based Compensation Arrangement by Share-based Payment Award, Expiration Date	ten years		
Stock Compensation Plan [Member]			
Stock Awards [Abstract]			
Nonemployee Director Stock Compensation Plan, Number of Shares Granted	55,141	43,128	49,649
Nonemployee Director Stock Compensation Plan, Fair Value of Shares Granted	1,100,000	849,000	879,000
Performance Share Awards [Member]			
Performance share awards [Abstract]			
Target Grant Of Shares Under Performance Awards	277,309	227,009	257,836
Participant Target Grant of Shares, Percentage Rate Range, Minimum	0.00%		
Participant Target Grant of Shares, Percentage Rate Range, Maximum	200.00%		
Historical Volitility Rate	50.00%		
Implied Volatility Rate	50.00%		
Share-based Compensation Arrangement by Share-based Payment Award, Fair Value Assumptions and Methodology [Abstract]			
Granted, weighted average grant-date fair value	$ 19.99	$ 17.40	$ 20.39
Expected volatility rate, minimum	23.20%	25.69%	40.40%
Expected volatility rate, maximum	32.18%	35.36%	50.98%
Risk-free interest rate, minimum	0.09%	0.13%	0.30%
Risk-free interest rate, maximum	1.34%	1.45%	1.36%
Discounted dividends, per share	1.23	1.04	1.79
Share awards vested in period, fair value		$ 3,500,000	$ 2,800,000
Share-based Compensation Arrangement by Share-based Payment Award, Equity Instruments Other than Options, Nonvested [Roll Forward]			
Nonvested at beginning of period, shares	669,685		
Nonvested at beginning of period, weighted average grant-date fair value	$ 22.19		
Granted, shares	278,252		

Granted, weighted average grant-date fair value	$ 19.99	$ 17.40	$ 20.39
Vested, shares	0		
Vested, weighted average grant-date fair value	$ 0		
Forfeited, shares	(185,783)		
Forfeited, weighted average grant-date fair value	$ 30.55		
Nonvested at end of period, shares	762,154	669,685	
Nonvested at end of period, weighted average grant-date fair value	$ 19.35	$ 22.19	

Summary of Significant Accounting Policies	12 Months Ended Dec. 31, 2011
Accounting Policies [Abstract]	
Summary of Significant Accounting Policies	

Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

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

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

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

Management has also evaluated the impact of events occurring after December 31, 2011, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents

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

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $29.8 million and $21.6 million as of December 31, 2011 and 2010, respectively. For more information, see Percentage-of-completion method in this note.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2011 and 2010, was $12.4 million and $15.3 million, respectively.

Inventories and natural gas in storage

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

	2011	2010
	(In thousands)	
Aggregates held for resale	**$ 78,518**	$ 79,894
Materials and supplies	**61,611**	57,324
Natural gas in storage (current)	**36,578**	34,557
Asphalt oil	**32,335**	25,234
Merchandise for resale	**32,165**	30,182
Other	**32,998**	25,706
Total	**$ 274,205**	$ 252,897

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $50.3 million and $48.0 million at December 31, 2011 and 2010, respectively.

Investments

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

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and production properties as described in 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 $15.1 million, $17.6 million and $17.4 million in 2011, 2010 and 2009, 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 exploration and 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:

	2011	2010	Weighted Average Depreciable Life in Years

			(Dollars in thousands, where applicable)
Regulated:			
Electric:			
Generation	**$ 546,783**	$ 538,071	47
Distribution	**255,232**	243,205	36
Transmission	**179,580**	161,972	44
Other	**86,929**	83,786	13
Natural gas distribution:			
Distribution	**1,257,360**	1,223,239	38
Other	**311,506**	285,606	23
Pipeline and energy services:			
Transmission	**386,227**	357,395	52
Gathering	**42,378**	41,931	19
Storage	**41,908**	33,967	51
Other	**36,179**	33,938	29
Nonregulated:			
Pipeline and energy services:			
Gathering	**198,864**	203,064	17
Other	**13,735**	13,512	10
Exploration and production:			
Natural gas and oil properties	**2,577,576**	2,320,967	*
Other	**37,570**	35,971	9
Construction materials and contracting:			
Land	**126,790**	124,018	—
Buildings and improvements	**67,627**	65,003	20
Machinery, vehicles and equipment	**902,136**	899,365	12
Construction in progress	**8,085**	4,879	—
Aggregate reserves	**395,214**	393,110	**
Construction services:			
Land	**4,706**	4,526	—
Buildings and improvements	**15,001**	14,101	22
Machinery, vehicles and equipment	**95,891**	94,252	7
Other	**9,198**	10,061	4
Other:			
Land	**2,837**	2,837	—
Other	**46,910**	29,727	24
Less accumulated depreciation, depletion and amortization	**3,361,208**	3,103,323	
Net property, plant and equipment	**$ 4,285,014**	$ 4,115,180	

* Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $2.04, $1.77 and $1.64 for the years ended December 31, 2011, 2010 and 2009, respectively. Includes natural gas and oil properties accounted for under the full-cost method, of which $232.5 and $182.4 million were excluded from amortization at December 31, 2011 and 2010, respectively.

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

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and 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 2011, 2010 and 2009. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

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

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach. If the fair value of a reporting unit is less than its carrying value, step two of the goodwill impairment test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the affected reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2011, 2010 and 2009, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded. 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 generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, 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 at March 31, 2009, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2009. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-down amounted to $620.0 million ($384.4 million after tax) for the year ended December 31, 2009.

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, 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, 2011, 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, 2011, 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, 2011, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2011	2010	2009	2008 and prior
		(In thousands)			
Acquisition	$185,773	$ 50,721	$ 71,315	$ 988	$ 62,749
Development	9,938	9,689	156	2	91
Exploration	27,439	24,389	2,710	72	268
Capitalized interest	9,312	3,539	3,096	44	2,633
Total costs not subject to amortization	$232,462	$ 88,338	$ 77,277	$ 1,106	$ 65,741

Costs not subject to amortization as of December 31, 2011, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Texas properties, Niobrara play, the Paradox Basin, the Green River Basin and the Big Horn Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $80.2 million and $87.3 million at December 31, 2011 and 2010, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs and estimated earnings in excess of billings on uncompleted contracts of $54.3 million and $46.6 million at December 31, 2011 and 2010, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $79.1 million and $65.2 million at December 31, 2011 and 2010, 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 $51.5 million and $51.1 million at December 31, 2011 and 2010, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $49.3 million and $50.4 million at December 31, 2011 and 2010, respectively. The long-term retainage which was included in deferred charges and other assets - other was $2.2 million and $700,000 at December 31, 2011 and 2010, 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 sales of 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. 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. For more information, see Note 8.

Asset retirement obligations

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

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $45.1 million and $37.0 million at December 31, 2011 and 2010, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $2.6 million and $6.6 million at December 31, 2011 and 2010, 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 positions in income taxes.

Foreign currency translation adjustment

The functional currency of the Company's investment in ECTE, 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 an average of the 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 2011 and 2010, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury. Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2011	2010	2009 *
	(In thousands)		
Weighted average common shares outstanding - basic	**188,763**	188,137	185,175
Effect of dilutive stock options and performance share awards	**142**	92	—
Weighted average common shares outstanding - diluted	**188,905**	188,229	185,175

* Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.

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 acquisition 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,		**2011**		2010		2009
		(In thousands)				
Interest, net of amount capitalized	**$**	**78,133**	$	80,962	$	81,267
Income taxes paid (refunded), net	**$**	**(12,287)**	$	46,892	$	39,807

For the year ended December 31, 2011, cash flows from investing activities do not include $24.0 million of capital expenditures, including amounts being financed with accounts payable, and therefore, do not have an impact on cash flows for the period.

New accounting standards

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 were effective on January 1, 2011. The guidance requires additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance is effective for the Company on January 1, 2012. The guidance will require additional disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The guidance, except for the portion that was indefinitely deferred, is effective for the Company on January 1, 2012, and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosure, but it will not impact the Company's results of operations, financial position or cash flows.

Disclosures about an Employer's Participation in a Multiemployer Plan In September 2011, the FASB issued guidance on an employer's participation in multiemployer benefit plans. The guidance was issued to enhance the transparency of disclosures about the significant multiemployer plans in which employers participate, the level of the employer's participation in those plans, the financial health of the plans and the nature of the employer's commitments to the plans. This guidance was effective for the Company on December 31, 2011, and must be applied retrospectively. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

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 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 loss, and their related tax effects for the years ended December 31 were as follows:

	2011	2010	2009
		(In thousands)	
Other comprehensive 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 $4,683, $(1,867) and $(2,509) in 2011, 2010 and 2009, respectively	**$ 7,900**	$ (3,077)	$ (4,094)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net	**—**	(3,750)	47,590

income, net of tax of $0, $(2,305) and $29,170 in 2011, 2010 and 2009, respectively			
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**7,900**	673	(51,684)
Postretirement liability adjustment, net of tax of $(13,573), $(3,609) and $6,291 in 2011, 2010 and 2009, respectively	**(22,427)**	(5,730)	9,918
Foreign currency translation adjustment, net of tax of $(832), $(3,486) and $6,814 in 2011, 2010 and 2009, respectively	**(1,295)**	(5,371)	10,568
Net unrealized gains on available-for-sale investments, net of tax of $44 in 2011	**82**	—	—
Total other comprehensive loss	**$ (15,740)**	$ (10,428)	$ (31,198)

The after-tax components of accumulated other comprehensive loss as of December 31, 2011, 2010 and 2009, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2009	$ (2,298)	$ (25,163)	$ 6,628	$ —	$ (20,833)
Balance at December 31, 2010	$ (1,625)	$ (30,893)	$ 1,257	$ —	$ (31,261)
Balance at December 31, 2011	**$ 6,275**	**$ (53,320)**	**$ (38)**	**$ 82**	**$ (47,001)**

Consolidated Balance Sheets (Parenthetical) (USD $)	Dec. 31, 2011	Dec. 31, 2010
Stockholders' equity:		
Common stock shares authorized (in shares)	500,000,000	500,000,000
Common stock par value (in dollars per share)	$ 1.00	$ 1.00
Common stock shares issued (in shares)	189,332,485	188,901,379
Treasury stock (in shares)	538,921	538,921

Preferred Stocks	12 Months Ended Dec. 31, 2011
Preferred Stocks [Abstract]	
Preferred Stocks	

Preferred Stocks

Preferred stocks at December 31 were as follows:

		2011		2010
		(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

For the years 2011, 2010 and 2009, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

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

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

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

Supplemental Financial Information Exploration and Production Details 2 (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Costs Incurred, Oil and Gas Property Acquisition, Exploration, and Development Activities [Line Items]			
Costs Incurred, Acquisition of Oil and Gas Properties with Proved Reserves	$ 3,999 [1]	$ 89,733 [1]	$ 3,879 [1]
Costs Incurred, Acquisition of Unproved Oil and Gas Properties	63,354 [1]	92,100 [1]	8,771 [1]
Costs Incurred, Exploration Costs	41,775 [1]	33,226 [1]	33,123 [1]
Costs Incurred, Development Costs	161,647 [1]	139,733 [1]	135,202 [1]
Capital Expenditures Related to Oil and Natural Gas Producing Activities	270,775 [1]	354,792 [1]	180,975 [1]
Net change in property, plant and equipment related to future liabilitie for asset retirement obligations that are excluded	$ (1,800)	$ 11,100	$ 2,000

[1] Excludes net additions/(reductions) to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of natural gas and oil wells, as discussed in Note 10, of $(1.8) million, $11.1 million and $2.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Supplemental Financial Information (Unaudited) (Details) (USD $) Share data in Thousands, except Per Share data, unless otherwise specified	3 Months Ended								12 Months Ended		
	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2010	Jun. 30, 2010	Mar. 31, 2010	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Operating revenues	$ 1,065,749,000	$ 1,152,181,000	$ 930,757,000	$ 901,805,000	$ 1,042,551,000	$ 1,125,923,000	$ 906,444,000	$ 834,777,000	$ 4,050,492,000	$ 3,909,695,000	$ 4,176,501,000
Operating expenses	939,172,000	1,032,760,000	848,454,000	823,739,000	912,377,000	1,016,961,000 [1]	817,782,000	751,848,000	3,644,125,000	3,498,968,000	4,329,598,000
Operating income (loss)	126,577,000	119,421,000	82,303,000	78,066,000	130,174,000	108,962,000 [1]	88,662,000	82,929,000	406,367,000	410,727,000	(153,097,000)
Income (loss) from continuing operations	74,088,000	64,100,000	45,235,000	42,529,000	92,300,000 [2]	61,010,000 [1]	48,938,000	41,772,000	225,952,000	244,020,000	(123,274,000)
Income (loss) from discontinued operations, net of tax	(13,080,000) [3]	(126,000)	(168,000)	448,000	(3,361,000)	0	0	0	(12,926,000) [4]	(3,361,000) [4]	0 [4]
Net income (loss)	61,008,000 [3]	63,974,000	45,067,000	42,977,000	88,939,000 [2]	61,010,000 [1]	48,938,000	41,772,000	213,026,000	240,659,000	(123,274,000)
Earnings per common share - basic [Abstract]											
Earnings (Loss) Before Discontinued Operations	$ 0.39	$ 0.34	$ 0.24	$ 0.22	$ 0.49 [2]	$ 0.32 [1]	$ 0.26	$ 0.22	$ 1.19	$ 1.29	$ (0.67)
Discontinued Operations, Net of Tax	$ (0.07) [3]	$ 0	$ 0	$ 0.01	$ (0.02)	$ 0	$ 0	$ 0	$ (0.07)	$ (0.01)	$ 0.00
Earnings (Loss) Per Common Share - Basic	$ 0.32 [3]	$ 0.34	$ 0.24	$ 0.23	$ 0.47 [2]	$ 0.32 [1]	$ 0.26	$ 0.22	$ 1.12	$ 1.28	$ (0.67)
Earnings per common share - diluted [Abstract]											
Earnings (Loss) Before Discontinued Operations	$ 0.39	$ 0.34	$ 0.24	$ 0.22	$ 0.49 [2]	$ 0.32 [1]	$ 0.26	$ 0.22	$ 1.19	$ 1.29	$ (0.67)
Discontinued Operations, Net of Tax	$ (0.07) [3]	$ 0	$ 0	$ 0.01	$ (0.02)	$ 0	$ 0	$ 0	$ (0.07)	$ (0.02)	$ 0.00
Earnings (Loss) Per Common Share - Diluted	$ 0.32 [3]	$ 0.34	$ 0.24	$ 0.23	$ 0.47 [2]	$ 0.32 [1]	$ 0.26	$ 0.22	$ 1.12	$ 1.27	$ (0.67)
Weighted average common shares outstanding - basic	188,794	188,794	188,794	188,671	188,281	188,170	188,129	187,963	188,763	188,137	185,175 [5]
Weighted Average Common Shares Outstanding - Diluted	188,932	188,797	188,968	188,815	188,374	188,338	188,267	188,220	188,905	188,229	185,175 [5]
Natural gas gathering arbitration charge, after tax						16,500,000				16,500,000	
Arbitration charge after tax	13,000,000								13,000,000		
Recognized gain on sale of ownership interests, after tax					$ 13,800,000						

[1] 2010 reflects a natural gas gathering arbitration charge of $16.5 million (after tax). For more information, see Note 19.

[2] 2010 reflects a $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines. For more information, see Note 4.

[3] 2011 reflects an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract. For more information, see Note 19.

[4] Reflected in the Other category.

[5] Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.

Document And Entity Information (USD $)	12 Months Ended Dec. 31, 2011	Feb. 17, 2012	Jun. 30, 2011
Entity Information [Line Items]			
Entity Registrant Name	MDU RESOURCES GROUP INC		
Entity Central Index Key	0000067716		
Current Fiscal Year End Date	--12-31		
Entity Well-known Seasoned Issuer	Yes		
Entity Voluntary Filers	No		
Entity Current Reporting Status	Yes		
Entity Filer Category	Large Accelerated Filer		
Entity Public Float			$ 4,247,855,190
Entity Common Stock, Shares Outstanding		188,819,307	
Document Fiscal Year Focus	2011		
Document Fiscal Period Focus	FY		
Document Type	10-K		
Amendment Flag	false		
Document Period End Date	Dec. 31, 2011		

Common Stock	12 Months Ended Dec. 31, 2011
Common Stock [Abstract]	
Common Stock	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 2009 through December 2011, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2011, 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 the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The most restrictive limitations are discussed below. Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.2 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2011. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $136 million of the Company's (excluding its subsidiaries) net assets would be restricted from use for dividend payments at December 31, 2011. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Nonqualified Benefit Plans (Details) (Supplemental Employee Retirement Plans, Defined Benefit [Member], USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Defined Benefit Plan Disclosure [Line Items]			
Investments in nonqualified benefit plans	$ 76,900,000	$ 77,500,000	
Net periodic benefit cost	8,100,000	7,800,000	8,800,000
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets, Aggregate Projected Benefit Obligation	113,800,000	99,400,000	
Defined Benefit Plan, Pension Plans with Accumulated Benefit Obligations in Excess of Plan Assets, Aggregate Accumulated Benefit Obligation	105,700,000	93,200,000	
Defined Benefit Plan, Assumptions Used Calculating Benefit Obligation, Discount Rate	4.00%	5.11%	
Defined Benefit Plan, Assumptions Used Calculating Benefit Obligation, Rate of Compensation Increase	4.00%	4.00%	
Defined Benefit Plan, Assumptions Used Calculating Net Periodic Benefit Cost, Discount Rate	5.11%	5.75%	
Defined Benefit Plan, Assumptions Used Calculating Net Periodic Benefit Cost, Rate of Compensation Increase	4.00%	4.00%	
Defined Benefit Plan, Expected Future Benefit Payments in Year One	5,200,000		
Defined Benefit Plan, Expected Future Benefit Payments in Year Two	5,900,000		
Defined Benefit Plan, Expected Future Benefit Payments in Year Three	5,800,000		
Defined Benefit Plan, Expected Future Benefit Payments in Year Four	6,900,000		
Defined Benefit Plan, Expected Future Benefit Payments in Year Five	6,800,000		
Defined Benefit Plan, Expected Future Benefit Payments in Five Fiscal Years Thereafter	38,300,000		
Equity Securities [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Investments in nonqualified benefit plans	38,400,000	39,500,000	
Life insurance carried on plan participants [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Investments in nonqualified benefit plans	31,800,000	30,700,000	
Other Investments [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Investments in nonqualified benefit plans	$ 6,700,000	$ 7,300,000	

Commitments and Contingencies (Details 5) (USD $)	12 Months Ended Dec. 31, 2011
Guarantor Obligations [Line Items]	
Amount of hedging obligations outstanding reflected on balance sheet and guaranteed by a related party	$ 4,300,000
Guarantor Obligations, Maximum Exposure, Undiscounted	85,600,000
Fixed Maximum Amounts Guaranteed By Year 2012	42,000,000
Fixed Maximum Amounts Guaranteed By Year 2013	34,400,000
Fixed Maximum Amounts Guaranteed By Year 2014	1,300,000
Fixed Maximum Amounts Guaranteed By Year 2015	100,000
Fixed Maximum Amounts Guaranteed By Year 2016	100,000
Fixed Maximum Amounts Guaranteed By Year 2018	800,000
Fixed Maximum Amounts Guaranteed By Year 2019	300,000
Expires on a specified number of days after the receipt of written notice	2,600,000
No scheduled maturity date	4,000,000
Amount Outstanding Under Guarantees That Is Reflected On Balance Sheet	500,000
Letters Of Credit	27,400,000
Outstanding letters of credit	0
Letters of credit set to expire in 2012	24,100,000
Letters of credit set to expire in 2013	3,300,000
Natural gas transportation and storage agreement fixed maximum amount of performance guarantee of a related party	5,000,000
The amount outstanding by a related party under the guarantee	1,200,000
Amount of surety bonds outstanding	$ 463,000,000

Consolidated Balance Sheets (USD $) In Thousands, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010
Current assets:		
Cash and cash equivalents	$ 162,772	$ 222,074
Receivables, net	646,251	583,743
Inventories	274,205	252,897
Deferred income taxes	40,407	32,890
Commodity derivative instruments	27,687	15,123
Prepayments and other current assets	43,316	60,441
Total current assets	1,194,638	1,167,168
Investments	109,424	103,661
Property, plant and equipment	7,646,222	7,218,503
Less accumulated depreciation, depletion and amortization	3,361,208	3,103,323
Net property, plant and equipment	4,285,014	4,115,180
Deferred charges and other assets: [Abstract]		
Goodwill	634,931 [1]	634,633 [1]
Other intangible assets, net	20,843	25,271
Other	311,275	257,636
Total deferred charges and other assets	967,049	917,540
Total assets	6,556,125	6,303,549
Current liabilities:		
Short-term borrowings	0	20,000
Long-term debt due within one year	139,267	72,797
Accounts payable	337,228	301,132
Taxes payable	70,176	56,186
Dividends payable	31,794	30,773
Accrued Compensation	47,804	40,121
Commodity derivative instruments	13,164	24,428
Other accrued liabilities	259,320	222,639
Total current liabilities	898,753	768,076
Long-term Debt, Excluding Current Maturities	1,285,411	1,433,955
Deferred credits and other liabilities:		
Deferred income taxes	769,166	672,269
Other liabilities	827,228	736,447
Total deferred credits and other liabilities	1,596,394	1,408,716
Stockholders' equity:		
Preferred stocks	15,000	15,000
Common stockholders' equity:		
Common stock shares authorized - 500,000,000 - issued - $1.00 par value, 189,332,485 shares at December 31, 2011 and 188,901,379 shares at December 31, 2010	189,332	188,901
Other paid-in capital	1,035,739	1,026,349

Retained earnings	1,586,123	1,497,439
Accumulated other comprehensive loss	(47,001)	(31,261)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,760,567	2,677,802
Total stockholders' equity	2,775,567	2,692,802
Total liabilities and stockholders' equity	$ 6,556,125	$ 6,303,549

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

Regulatory Assets and Liabilities	12 Months Ended Dec. 31, 2011

[Regulatory Assets and Liabilities Disclosure [Abstract]]

[Regulatory Assets and Liabilities]

Regulatory Assets and Liabilities

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

	Estimated Recovery Period *	2011	2010
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	**171,492**	103,818
Deferred income taxes	**	**119,189**	114,427
Taxes recoverable from customers (a)	—	**12,433**	11,961
Plant costs (a)	Over plant lives	**10,256**	9,964
Long-term debt refinancing costs (a)	Up to 27 years	**10,112**	11,101
Costs related to identifying generation development (a)	Up to 15 years	**9,817**	13,777
Natural gas supply derivatives (b)	Up to 1 year	**437**	9,359
Natural gas cost recoverable through rate adjustments (b)	Up to 28 months	**2,622**	6,609
Other (a) (b)	Largely within 1 year	**22,651**	35,225
Total regulatory assets		**359,009**	316,241
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		**289,972**	276,652
Deferred income taxes**		**84,963**	64,017
Natural gas costs refundable through rate adjustments (d)		**45,064**	36,996
Taxes refundable to customers (c)		**31,837**	19,352
Other (c) (d)		**8,393**	16,080
Total regulatory liabilities		**460,229**	413,097
Net regulatory position		**(101,220)**	(96,856)

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

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

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

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

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

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

(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of

December 31, 2011, approximately $216.4 million of regulatory assets were not earning a rate of return.

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

Goodwill and Other Intangible Assets	12 Months Ended Dec. 31, 2011
Goodwill and Intangible Assets Disclosure [Abstract]	
Goodwill and Other Intangible Assets	

Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2011, were as follows:

	Balance as of January 1, 2011 *	Goodwill Acquired During the Year **	Balance as of December 31, 2011 *
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	9,737	—	9,737
Exploration and production	—	—	—
Construction materials and contracting	176,290	—	176,290
Construction services	102,870	298	103,168
Other	—	—	—
Total	$ 634,633	$ 298	$ 634,931

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

** Includes a purchase price adjustment that was not material related to an acquisition in a prior period.

The changes in the carrying amount of goodwill for the year ended December 31, 2010, were as follows:

	Balance as of January 1, 2010 *	Goodwill Acquired During the Year **	Balance as of December 31, 2010 *
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	7,857	1,880	9,737
Exploration and production	—	—	—
Construction materials and contracting	175,743	547	176,290
Construction services	100,127	2,743	102,870
Other	—	—	—
Total	$ 629,463	$ 5,170	$ 634,633

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

** 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:

	2011	2010
	(In thousands)	
Customer relationships	**$ 21,702**	$ 24,942
Accumulated amortization	**(10,392)**	(11,625)
	11,310	13,317
Noncompete agreements	**7,685**	9,405
Accumulated amortization	**(5,371)**	(6,425)
	2,314	2,980
Other	**11,442**	13,217
Accumulated amortization	**(4,223)**	(4,243)
	7,219	8,974
Total	**$ 20,843**	$ 25,271

Amortization expense for intangible assets for the years ended December 31, 2011, 2010 and 2009, was $3.7 million, $4.2 million and $5.0 million, respectively. Estimated amortization expense for intangible assets is $3.8 million in 2012, $3.7 million in 2013, $3.3 million in 2014, $2.6 million in 2015, $2.1 million in 2016 and $5.3 million thereafter.

Jointly Owned Facilities	12 Months Ended Dec. 31, 2011

Regulated Operations [Abstract]

Jointly Owned Facilities

Jointly Owned Facilities

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

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses 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:

	2011	2010
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 63,715**	$ 60,404
Less accumulated depreciation	**42,475**	41,136
	$ 21,240	$ 19,268
Coyote Station:		
Utility plant in service	**$ 131,719**	$ 131,395
Less accumulated depreciation	**86,788**	84,710
	$ 44,931	$ 46,685
Wygen III:*		
Utility plant in service	**$ 63,300**	$ 63,215
Less accumulated depreciation	**2,106**	838
	$ 61,194	$ 62,377

* Began commercial operation on April 1, 2010.

Stock-Based Compensation

12 Months Ended Dec. 31, 2011

Share-based Compensation [Abstract]

Stock-Based Compensation

Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2011, there are 6.3 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense was $3.5 million, net of income taxes of $2.2 million in 2011; $3.4 million, net of income taxes of $2.1 million in 2010; and $3.4 million, net of income taxes of $2.2 million in 2009.

As of December 31, 2011, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.5 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock options

The Company had granted stock options to directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vested after nine years, but the plan provided for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expired ten years after the date of grant. Options granted to employees vested three years after the date of grant and expired ten years after the date of grant. Options granted to directors vested at the date of grant and expire ten 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, 2011, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	440,984	$13.34
Forfeited	(3,893)	13.22
Exercised	(430,341)	13.34
Balance at end of year	6,750	13.03
Exercisable at end of year	6,750	$13.03

Stock options outstanding as of December 31, 2011, had an aggregate intrinsic value of $57,000, and approximately six months of remaining contractual life. The aggregate intrinsic value represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2011, which would have been received by the option holders had all option holders exercised their options as of that date.

The Company received cash of $5.7 million, $5.0 million and $2.1 million from the exercise of stock options for the years ended December 31, 2011, 2010 and 2009, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009, was $3.3 million, $2.6 million and $1.3 million, respectively.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 55,141 shares with a fair value of $1.1 million, 43,128 shares with a fair value of $849,000 and 49,649 shares with a fair value of $879,000 issued under this plan during the years ended December 31, 2011, 2010 and 2009, 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, 2011, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2009	2009-2011	257,836
March 2010	2010-2012	227,009

February 2011	2011-2013	277,309

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2011, 2010 and 2009 were:

			2011			2010			2009
Grant-date fair value			**$19.99**			$17.40			$20.39
Blended volatility range	**23.20%**	**-**	**32.18%**	25.69%	-	35.36%	40.40%	-	50.98%
Risk-free interest rate range	**.09%**	**-**	**1.34%**	.13%	-	1.45%	.30%	-	1.36%
Discounted dividends per share			**$1.23**			$1.04			$1.79

There were no performance shares that vested in 2011. The fair value of performance share awards that vested during the years ended December 31, 2010 and 2009, was $3.5 million and $2.8 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2011, was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	669,685	$	22.19
Granted	278,252		19.99
Vested	—		—
Forfeited	(185,783)		30.55
Nonvested at end of period	762,154	$	19.35

Jointly Owned Facilities Jointly Owned Facilities (Details 2) (USD $) In Thousands, unless otherwise specified	Dec. 31, 2011		Dec. 31, 2010	
Big Stone Station [Member]				
Public Utility, Property, Plant and Equipment [Line Items]				
Utility plant in service	$ 63,715		$ 60,404	
Less accumulated depreciation	42,475		41,136	
Utility plant in services net	21,240		19,268	
Coyote Station [Member]				
Public Utility, Property, Plant and Equipment [Line Items]				
Utility plant in service	131,719		131,395	
Less accumulated depreciation	86,788		84,710	
Utility plant in services net	44,931		46,685	
Wygen III [Member]				
Public Utility, Property, Plant and Equipment [Line Items]				
Utility plant in service	63,300	[1]	63,215	[1]
Less accumulated depreciation	2,106	[1]	838	[1]
Utility plant in services net	$ 61,194	[1]	$ 62,377	[1]

[1] Began commercial operation on April 1, 2010.

Debt	12 Months Ended Dec. 31, 2011

Debt Disclosure [Abstract]

Debt

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, 2011. 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, 2011	Amount Outstanding at December 31, 2010	Letters of Credit at December 31, 2011	Expiration Date
				(Dollars in millions)			
MDU Resources Group, Inc.	Commercial paper/ Revolving credit agreement	(a)	$ 100.0	$ — (h)	$ 20.0 (b)	$ —	5/26/15
Cascade Natural Gas Corporation	Revolving credit agreement		$ 50.0 (c)	$ —	$ —	$ 1.9 (d)	12/28/12 (e)
Intermountain Gas Company	Revolving credit agreement		$ 65.0 (f)	$ 8.1	$ 20.2	$ —	8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement	(g)	$ 400.0	$ — (h)	$ — (h)	$ 21.6 (d)	12/13/12

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 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 that was classified as short-term borrowings because the revolving credit agreement expired within one year.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.
(e) Provisions allow for an extension of up to two years upon consent of the banks.
(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(g) 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.
(h) Amount outstanding under commercial paper program.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings as of December 31, 2011, would have been classified as short-term borrowings because the revolving credit agreement expires within one year. Any commercial paper borrowings as of December 31, 2010, would have been classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement contains 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. Other covenants include restrictions on the sale of certain assets and on the making of certain loans and investments.

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

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.

Long-term debt

MDU Resources Group, Inc. On May 26, 2011, the Company entered into a new revolving credit agreement, which replaced the revolving credit agreement that expired on June 21, 2011. The Company's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings under this agreement would be classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The commercial paper borrowings outstanding as of December 31, 2010, were classified as short-term borrowings because the previous revolving credit agreement expired within one year.

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

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

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

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 a specified amount, (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 that is in excess of $10 million, then Intermountain shall be in default under the revolving credit agreement.

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired in 2010; however, there is debt outstanding that is reflected in the following table. The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain’s total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

Centennial Energy Holdings, Inc. The ability to request additional borrowings under an uncommitted long-term master shelf agreement expired; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term master shelf agreement contains 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 60 percent. 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.

Williston Basin Interstate Pipeline Company The ability to request additional borrowings under the uncommitted long-term private shelf agreement expired December 23, 2011; however, there is debt outstanding that is reflected in the following table. 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:

	2011	2010
	(In thousands)	
Senior Notes at a weighted average rate of 6.01%, due on dates ranging from May 15, 2012 to March 8, 2037	**$ 1,287,576**	$ 1,358,848
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	**40,469**	41,189
Credit agreements at a weighted average rate of 2.98%, due on dates ranging from September 30, 2012 to November 30, 2038	**15,633**	25,715
Total long-term debt	**1,424,678**	1,506,752
Less current maturities	**139,267**	72,797
Net long-term debt	**$ 1,285,411**	$ 1,433,955

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2011, aggregate $139.3 million in 2012; $267.3 million in 2013; $9.3 million in 2014; $266.4 million in 2015; $288.4 million in 2016 and $454.0 million thereafter.

Fair Value Measurements Fair Value Measurements (Details) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Schedule of Available-for-sale Securities [Line Items]			
Investments used to satisfy obligations under nonqualified benefit plans	$ 38,400,000	$ 39,500,000	
Before tax amount of increase (decrease) in fair value of investments used to satisfy obligations under nonqualified benefit plans	(1,100,000)	5,800,000	7,100,000
Available-for-sale Securities [Member]			
Available-for-sale Securities [Abstract]			
Available-for-sale Securities, Gross Unrealized Losses	(5,000)		
Available-for-sale Securities	59,704,000		
Available-for-sale Securities, Amortized Cost Basis	53,109,000		
Available-for-sale Securities, Gross Unrealized Gains	6,600,000		
Insurance Investment Contract [Member]			
Available-for-sale Securities [Abstract]			
Available-for-sale Securities, Gross Unrealized Losses	0		
Available-for-sale Securities	38,352,000		
Available-for-sale Securities, Amortized Cost Basis	31,884,000		
Available-for-sale Securities, Gross Unrealized Gains	6,468,000		
Auction Rate Securities [Member]			
Available-for-sale Securities [Abstract]			
Available-for-sale Securities, Gross Unrealized Losses	0		
Available-for-sale Securities	11,400,000		
Available-for-sale Securities, Amortized Cost Basis	11,400,000		
Available-for-sale Securities, Gross Unrealized Gains	0		
Collateralized Mortgage Backed Securities [Member]			
Available-for-sale Securities [Abstract]			
Available-for-sale Securities, Gross Unrealized Losses	(5,000)		
Available-for-sale Securities	8,296,000		
Available-for-sale Securities, Amortized Cost Basis	8,206,000		
Available-for-sale Securities, Gross Unrealized Gains	95,000		
US Treasury Securities [Member]			
Available-for-sale Securities [Abstract]			
Available-for-sale Securities, Gross Unrealized Losses	0		
Available-for-sale Securities	1,656,000		
Available-for-sale Securities, Amortized Cost Basis	1,619,000		
Available-for-sale Securities, Gross Unrealized Gains	$ 37,000		

Derivative Instruments	12 Months Ended Dec. 31, 2011
Derivative Instruments and Hedging Activities Disclosure [Abstract]	
Derivative Instruments	(see below)

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, 2011, the Company had no outstanding foreign currency hedges.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2011 and 2010, credit risk was not material.

Cascade and Intermountain

At December 31, 2011, Cascade held a natural gas swap agreement with total forward notional volumes of 305,000 MMBtu, which was not designated as a hedge. Cascade utilizes, and Intermountain periodically utilizes, 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. Periodic changes in the fair market value of the derivative instruments are recorded 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 years ended December 31, 2011 and 2010, the change in the fair market value of the derivative instruments of $8.9 million and $18.5 million, respectively, were recorded as a decrease to 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 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's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $437,000. 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, 2011, was $437,000.

Fidelity

At December 31, 2011, Fidelity held natural gas swap agreements with total forward notional volumes of 10.8 million MMBtu, natural gas basis swap agreements with total forward notional volumes of 3.5 million MMBtu, and oil swap and collar agreements with total forward notional volumes of 4.0 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.

As of December 31, 2011, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 24 months.

Centennial

At December 31, 2011, Centennial held interest rate swap agreements with a total notional amount of $60.0 million, which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. Centennial's interest rate swap agreements have mandatory termination dates ranging from October 2012 through June 2013.

Fidelity and Centennial

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). To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the year ended December 31, 2011, $1.8 million (before tax) of hedge ineffectiveness related to natural gas and oil derivative instruments was reclassified as a gain into operating revenues and is reflected on the Consolidated Statements of Income. The amount of hedge ineffectiveness was immaterial for the years ended December 31, 2010 and 2009, 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 the natural gas and oil derivative instruments are reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the natural gas and oil quantities are settled. The proceeds received for natural gas and oil production are generally based on market prices. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings. 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.

Based on December 31, 2011, fair values, over the next 12 months net gains of approximately $8.7 million (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices and interest rates, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $18.4 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, 2011, was $18.4 million.

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

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 27,687	$ 15,123
	Other assets - noncurrent	2,768	4,104
		30,455	19,227
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	—	—
	Other assets - noncurrent	—	—
		—	—
Total asset derivatives		$ 30,455	$ 19,227

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$ 12,727	$ 15,069
	Other liabilities - noncurrent	937	6,483
Interest rate derivatives	Other accrued liabilities	827	—
	Other liabilities - noncurrent	3,935	—
		18,426	21,552
Not designated as hedges:			

Commodity derivatives	Commodity derivative instruments	437	9,359
	Other liabilities - noncurrent	—	—
		437	9,359
Total liability derivatives		$ 18,863	$ 30,911

Fair Value Measurements	12 Months Ended Dec. 31, 2011

Fair Value Disclosures [Abstract]

Fair Value Measurements

Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments 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 $38.4 million and $39.5 million as of December 31, 2011 and 2010, respectively, are classified as Investments on the Consolidated Balance Sheets. The decrease in the fair value of these investments for the year ended December 31, 2011, was $1.1 million (before tax). The increase in the fair value of these investments for the years ended December 31, 2010 and 2009, was $5.8 million (before tax) and $7.1 million (before tax), respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its remaining available-for-sale securities, which include auction rate securities, mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. The Company's 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. Unrealized gains or losses on mortgage-backed securities and U.S. Treasury securities are recorded in accumulated other comprehensive income (loss) as discussed in Note 1. Details of available-for-sale securities were as follows:

December 31, 2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Insurance investment contract	$ 31,884	$ 6,468	$ —	$ 38,352
Auction rate securities	11,400	—	—	11,400
Mortgage-backed securities	8,206	95	(5)	8,296
U.S. Treasury securities	1,619	37	—	1,656
Total	$ 53,109	$ 6,600	$ (5)	$ 59,704

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

	Fair Value Measurements at December 31, 2011, 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, 2011
	(In thousands)			
Assets:				
Money market funds	$ —	$ 97,500	$ —	$ 97,500
Available-for-sale securities:				
Insurance investment contract*	—	38,352	—	38,352
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,296	—	8,296
U.S. Treasury securities	—	1,656	—	1,656
Commodity derivative instruments - current	—	27,687	—	27,687
Commodity derivative instruments - noncurrent	—	2,768	—	2,768
Total assets measured at fair value	$ —	$ 187,659	$ —	$ 187,659
Liabilities:				
Commodity derivative instruments - current	$ —	$ 13,164	$ —	$ 13,164
Commodity derivative instruments - noncurrent	—	937	—	937
Interest rate derivative instruments - current	—	827	—	827

Interest rate derivative instruments - noncurrent	—	3,935	—	3,935
Total liabilities measured at fair value	$ —	$ 18,863	$ —	$ 18,863

* The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

	Fair Value Measurements at December 31, 2010, 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, 2010
		(In thousands)		
Assets:				
Money market funds	$ —	$ 166,620	$ —	$ 166,620
Available-for-sale securities:				
Insurance investment contract*	—	39,541	—	39,541
Auction rate securities	—	11,400	—	11,400
Commodity derivative instruments - current	—	15,123	—	15,123
Commodity derivative instruments - noncurrent	—	4,104	—	4,104
Total assets measured at fair value	$ —	$ 236,788	$ —	$ 236,788
Liabilities:				
Commodity derivative instruments - current	$ —	$ 24,428	$ —	$ 24,428
Commodity derivative instruments - noncurrent	—	6,483	—	6,483
Total liabilities measured at fair value	$ —	$ 30,911	$ —	$ 30,911

* The insurance investment contract invests approximately 35 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 31 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources such as the fund itself.

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2011 and 2010, there were no significant transfers between Levels 1 and 2.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only, and 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:

	2011		2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 1,424,678**	**$ 1,592,807**	$ 1,506,752	$ 1,621,184

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

Asset Retirement Obligations	12 Months Ended Dec. 31, 2011
Asset Retirement Obligation [Abstract]	
Asset Retirement Obligations	

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 facilities and buildings, and certain other obligations.

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

	2011	2010
	(In thousands)	
Balance at beginning of year	**$ 95,970**	$ 76,359
Liabilities incurred	**3,870**	8,608
Liabilities acquired	**—**	5,272
Liabilities settled	**(10,418)**	(10,740)
Accretion expense	**4,466**	3,588
Revisions in estimates	**3,921**	12,621
Other	**342**	262
Balance at end of year	**$ 98,151**	$ 95,970

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, 2011 and 2010, was $5.7 million and $5.7 million, respectively.

Long-term Debt (Details) (USD $)	Dec. 31, 2011	Dec. 31, 2010
Long term debt outstanding [Abstract]		
Net long-term debt	$ 1,285,411,000	$ 1,433,955,000
Senior Notes [Member]		
Long term debt outstanding [Abstract]		
Weighted average interest rate (in hundredths)	6.01%	
Medium-term Notes [Member]		
Long term debt outstanding [Abstract]		
Weighted average interest rate (in hundredths)	7.72%	
Other Notes [Member]		
Long term debt outstanding [Abstract]		
Weighted average interest rate (in hundredths)	5.24%	
Loans Payable [Member]		
Long term debt outstanding [Abstract]		
Weighted average interest rate (in hundredths)	2.98%	
MDU Resources Group, Inc [Member]		
Long term debt outstanding [Abstract]		
Long-term Debt	280,900,000	
Net long-term debt	280,781,000	280,889,000
Long Term Debt Maturities [Abstract]		
2012	100,000	
2013	100,000	
2014	100,000	
2015	100,000	
2016	50,000,000	
Thereafter 2016	230,500,000	
Long-term Debt [Member]		
Long term debt outstanding [Abstract]		
Long-term Debt	1,424,678,000	1,506,752,000
Less current maturities	139,267,000	72,797,000
Net long-term debt	1,285,411,000	1,433,955,000
Long Term Debt Maturities [Abstract]		
2012	139,300,000	
2013	267,300,000	
2014	9,300,000	
2015	266,400,000	
2016	288,400,000	
Thereafter 2016	454,000,000	
Long-term Debt [Member] | Senior Notes [Member]		
Long term debt outstanding [Abstract]		
Long-term Debt	1,287,576,000	1,358,848,000

Long-term Debt [Member] | Medium-term Notes [Member]		
Long term debt outstanding [Abstract]		
Long-term Debt	81,000,000	81,000,000
Long-term Debt [Member] | Other Notes [Member]		
Long term debt outstanding [Abstract]		
Long-term Debt	40,469,000	41,189,000
Long-term Debt [Member] | Loans Payable [Member]		
Long term debt outstanding [Abstract]		
Long-term Debt	15,633,000	25,715,000
Long-term Debt [Member] | Master Shelf Agreement Member [Member] | MDU Energy Capital, LLC [Member]		
Long-term Debt Covenants [Abstract]		
Ratio of total debt to adjusted total capitalization as specified in debt convenants	70.00%	
Ratio of subsidiary debt to subsidiary capitalization as specified in debt convenants	65.00%	
Ratio of total debt to total capitalization as specified in debt convenants.	65.00%	
Long-term Debt [Member] | Uncommitted Long Term Private Shelf Agreement [Member] | Williston Basin Interstate Pipeline Company [Member]		
Long-term Debt Covenants [Abstract]		
Ratio of total debt to total capitalization as specified in debt convenants.	55.00%	
Long-term Debt [Member] | Revolving Credit Agreement [Member] | MDU Resources Group, Inc [Member]		
Long-term Debt Covenants [Abstract]		
Ratio of funded debt to total capitalization as specified in debt convenants	65.00%	
Ratio of funded debt capitalization - Company alone, as specified in debt convenants	65.00%	
Long-term Debt [Member] | Revolving Credit Agreement [Member] | Intermountain Gas Company [Member]		
Long-term Debt Covenants [Abstract]		
Ratio of funded debt to total capitalization as specified in debt convenants	65.00%	
Conditions resulting in an early termination date under any swap contract that is in excess of this amount	$ 10,000,000	

Regulatory Matters and Revenues Subject to Refund (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended
	Dec. 31, 2011
Regulated Operations [Abstract]	
Estimated project cost of the natural gas turbine and associated facilities	$ 85.6

Preferred Stocks (Details) (USD $) In Thousands, except Share data, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Class of Stock [Line Items]			
Preferred stocks	$ 15,000	$ 15,000	
Preferred stock redemption price upon liquidation (in dollars per share)	$ 100.00		
Cumulative Preferred Stock, Par Value $100 Issuable in Series [Member]			
Class of Stock [Line Items]			
Authorized Preferred cumulative shares (in shares)	500,000	500,000	
Cumulative Preferred shares, par value (in dollars per share)	$ 100.00	$ 100.00	
Preferred Stock, Series 4.50% [Member]			
Class of Stock [Line Items]			
Preferred stocks	10,000	10,000	
Preferred Stock, $100 Par Value	4.50%	4.50%	4.50%
Preferred shares outstanding (in shares)	100,000	100,000	
Preferred stock redemption price at the option of the company (in dollars per share)	$ 105.00		
Preferred Stock, Dividends Per Share, Declared	$ 4.50	$ 4.50	$ 4.50
Preferred Stock, Series 4.70% [Member]			
Class of Stock [Line Items]			
Preferred stocks	$ 5,000	$ 5,000	
Preferred Stock, $100 Par Value	4.70%	4.70%	4.70%
Preferred shares outstanding (in shares)	50,000	50,000	
Preferred stock redemption price at the option of the company (in dollars per share)	$ 102.00		
Preferred Stock, Dividends Per Share, Declared	$ 4.70	$ 4.70	$ 4.70
Cumulative Preferred Stock A, Without Par Value, Issuable in Series [Member]			
Class of Stock [Line Items]			
Authorized Preferred cumulative shares (in shares)	1,000,000	1,000,000	
Cumulative Preference Stock , Without Par Value, Issuable in Series [Member]			
Class of Stock [Line Items]			
Authorized Preferred cumulative shares (in shares)	500,000	500,000	

Credit Facilities (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended Dec. 31, 2011	Dec. 31, 2010
Line of Credit Facility and Other Debt [Abstract]		
Letters of Credit at end of period	$ 27.4	
Long-term Debt [Member] | Commercial Paper Revolving Credit Agreement [Member] | MDU Resources Group, Inc [Member]		
Line of Credit Facility and Other Debt [Abstract]		
Facility Limit	100.0	
Amount outstanding, end of period	0 [1]	20.0 [2]
Letters of Credit at end of period	0	
Expiration Date	5/26/2015	
Commercial paper program supported by revolving credit agreement with various banks	125	
Long-term Debt [Member] | Revolving Credit Agreement [Member] | MDU Resources Group, Inc [Member]		
Line of Credit Facility and Other Debt [Abstract]		
Revolving Credit Agreement	100	
Option to increase borrowings, maximum amount	150	
Ratio of funded debt to total capitalization as specified in debt convenants	65.00%	
Ratio of funded debt capitalization - Company alone, as specified in debt convenants	65.00%	
Long-term Debt [Member] | Revolving Credit Agreement [Member] | Intermountain Gas Company [Member]		
Line of Credit Facility and Other Debt [Abstract]		
Facility Limit	65.0 [3]	
Amount outstanding, end of period	8.1	20.2
Letters of Credit at end of period	0	
Expiration Date	8/11/2013	
Option to increase borrowings, maximum amount	80	
Ratio of funded debt to total capitalization as specified in debt convenants	65.00%	
Conditions resulting in an early termination date under any swap contract that is in excess of this amount	10	
Long-term Debt [Member] | Master Shelf Agreement Member [Member] | MDU Energy Capital, LLC [Member]		
Line of Credit Facility and Other Debt [Abstract]		
Ratio of total debt to total capitalization as specified in debt convenants.	65.00%	
Ratio of total debt to adjusted total capitalization as specified in debt convenants	70.00%	
Ratio of subsidiary debt to subsidiary capitalization as specified in debt convenants	65.00%	
Ratio of EBIT to Interest Expense	150.00%	
Long-term Debt [Member] | Master Shelf Agreement Member [Member] | Centennial Energy Holdings, Inc [Member]		
Line of Credit Facility and Other Debt [Abstract]		
Ratio of total debt to total capitalization as specified in debt convenants.	60.00%	
Ratio of EBITDA to Interest Expense	175.00%	

Short-term Debt [Member] | Commercial Paper Revolving Credit Agreement [Member] | Centennial Energy Holdings, Inc [Member]		
Line of Credit Facility and Other Debt [Abstract]		
Facility Limit	400.0	
Amount outstanding, end of period	0 [1]	0 [1]
Letters of Credit at end of period	21.6 [4]	
Expiration Date	12/13/2012	
Commercial paper program supported by revolving credit agreement with various banks	400	
Short-term Debt [Member] | Revolving Credit Agreement [Member] | Cascade Natural Gas Corporation [Member]		
Line of Credit Facility and Other Debt [Abstract]		
Facility Limit	50.0 [5]	
Amount outstanding, end of period	0	0
Letters of Credit at end of period	1.9 [4]	
Expiration Date	12/28/2012	
Revolving Credit Agreement	50	
Option to increase borrowings, maximum amount	75	
Option to extend term of loan facility, maximum (in years)	two years	
Ratio of total debt to total capitalization as specified in debt convenants.	65.00%	
Short-term Debt [Member] | Revolving Credit Agreement [Member] | Centennial Energy Holdings, Inc [Member]		
Line of Credit Facility and Other Debt [Abstract]		
Revolving Credit Agreement	400	
Option to increase borrowings, maximum amount	$ 450	
Ratio of total debt to total capitalization as specified in debt convenants.	65.00%	

[1] Amount outstanding under commercial paper program.

[2] Amount outstanding under commercial paper program that was classified as short-term borrowings because the revolving credit agreement expired within one year.

[3] Certain provisions allow for increased borrowings, up to a maximum of $80 million.

[4] The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.

[5] Certain provisions allow for increased borrowings, up to a maximum of $75 million.

Supplemental Financial Information Exploration and Production (Details) (USD $) In Thousands, unless otherwise specified	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]			
Capitalized costs, oil and gas producing activities, subject to amortization	$ 2,345,114	$ 2,138,565	$ 1,815,380
Capitalized Costs of Unproved Properties Excluded from Amortization, Cumulative	232,462	182,402	178,214
Capitalized Costs, Oil and Gas Producing Activities, Gross	2,577,576	2,320,967	1,993,594
Capitalized Costs, Accumulated Depreciation, Depletion, Amortization and Valuation Allowance Relating to Oil and Gas Producing Activities	1,229,654	1,093,723	969,630
Capitalized Costs, Oil and Gas Producing Activities, Net	$ 1,347,922	$ 1,227,244	$ 1,023,964

Fair Value Measurements (Tables)	12 Months Ended Dec. 31, 2011

Fair Value Disclosures [Abstract]

Available-for-sale Securities [Table Text Block]

Details of available-for-sale securities were as follows:

December 31, 2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Insurance investment contract	$ 31,884	$ 6,468	$ —	$ 38,352
Auction rate securities	11,400	—	—	11,400
Mortgage-backed securities	8,206	95	(5)	8,296
U.S. Treasury securities	1,619	37	—	1,656
Total	$ 53,109	$ 6,600	$ (5)	$ 59,704

Assets and liabilities measured at fair value on a recurring basis

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

	Fair Value Measurements at December 31, 2011, 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, 2011
	(In thousands)			
Assets:				
Money market funds	$ —	$ 97,500	$ —	$ 97,500
Available-for-sale securities:				
Insurance investment contract*	—	38,352	—	38,352
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,296	—	8,296
U.S. Treasury securities	—	1,656	—	1,656
Commodity derivative instruments - current	—	27,687	—	27,687
Commodity derivative instruments - noncurrent	—	2,768	—	2,768
Total assets measured at fair value	$ —	$ 187,659	$ —	$ 187,659
Liabilities:				
Commodity derivative instruments - current	$ —	$ 13,164	$ —	$ 13,164
Commodity derivative instruments - noncurrent	—	937	—	937
Interest rate derivative instruments - current	—	827	—	827
Interest rate derivative instruments - noncurrent	—	3,935	—	3,935
Total liabilities measured at fair value	$ —	$ 18,863	$ —	$ 18,863

* The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

	Fair Value Measurements at December 31, 2010, 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, 2010
	(In thousands)			
Assets:				
Money market funds	$ —	$ 166,620	$ —	$ 166,620
Available-for-sale securities:				
Insurance investment contract*	—	39,541	—	39,541

Auction rate securities		—		11,400		—		11,400
Commodity derivative instruments - current		—		15,123		—		15,123
Commodity derivative instruments - noncurrent		—		4,104		—		4,104
Total assets measured at fair value	$	—	$	236,788	$	—	$	236,788
Liabilities:								
Commodity derivative instruments - current	$	—	$	24,428	$	—	$	24,428
Commodity derivative instruments - noncurrent		—		6,483		—		6,483
Total liabilities measured at fair value	$	—	$	30,911	$	—	$	30,911

* The insurance investment contract invests approximately 35 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 31 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

Fair value of long term debt outstanding

The estimated fair value of the Company's long-term debt at December 31 was as follows:

	2011		2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 1,424,678**	**$ 1,592,807**	$ 1,506,752	$ 1,621,184

Summary of Significant Accounting Policies (Details 8) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Net unrealized gain (loss) on derivative instruments qualifying as hedges: [Abstract]			
Net unrealized gain (loss) on derivative instruments arising during the period	$ 7,900,000	$ (3,077,000)	$ (4,094,000)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income	0	(3,750,000)	47,590,000
Net unrealized gain (loss) on derivative instruments qualifying as hedges	7,900,000	673,000	(51,684,000)
Postretirement liability adjustment, net of tax	(22,427,000)	(5,730,000)	9,918,000
Foreign currency translation adjustment, net of tax	(1,295,000)	(5,371,000)	10,568,000
Net unrealized gains on available-for-sale investments, net of tax	82,000	0	0
Other Comprehensive Income (Loss), Net of Tax	(15,740,000)	(10,428,000)	(31,198,000)
Other Comprehensive Income (Loss), Parenthetical [Abstract]			
Other Comprehensive Income (Loss), Unrealized Gain (Loss) on Derivatives Arising During Period, Tax	4,683,000	(1,867,000)	(2,509,000)
Other Comprehensive Income (Loss), Reclassification Adjustment on Derivatives Included in Net Income, Tax	0	(2,305,000)	29,170,000
Other Comprehensive Income (Loss), Pension and Other Postretirement Benefit Plans, Tax	(13,573,000)	(3,609,000)	6,291,000
Other Comprehensive Income (Loss), Unrealized Holding Gain (Loss) on Securities Arising During Period, Tax	44,000	0	0
Other Comprehensive Income (Loss), Foreign Currency Translation Adjustment, Tax	(832,000)	(3,486,000)	6,814,000
Accumulated Other Comprehensive Income (Loss), Net of Tax [Abstract]			
Net unrealized gain (loss) on derivative instruments qualifying as hedges	6,275,000	(1,625,000)	(2,298,000)
Post-retirement liability adjustment	(53,320,000)	(30,893,000)	(25,163,000)
Foreign currency translation adjustment	(38,000)	1,257,000	6,628,000
Accumulated Other Comprehensive Income (Loss), Available-for-sale Securities Adjustment, Net of Tax	82,000	0	0
Total accumulated other comprehensive income (loss)	$ (47,001,000)	$ (31,261,000)	$ (20,833,000)

Business segment data

Segment Reporting [Abstract]

Business segment data

	12 Months Ended Dec. 31, 2011

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 ECTE.

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

The pipeline and energy services segment provides natural gas transportation, underground storage 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 other energy-related services.

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

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

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

	2011	2010	2009
		(In thousands)	
External operating revenues:			
Electric	**$ 225,468**	$ 211,544	$ 196,171
Natural gas distribution	**907,400**	892,708	1,072,776
Pipeline and energy services	**210,846**	254,776	235,322
	1,343,714	1,359,028	1,504,269

Exploration and production	**359,873**	318,570	338,425
Construction materials and contracting	**1,509,538**	1,445,148	1,515,122
Construction services	**834,918**	786,802	818,685
Other	**2,449**	147	—
	2,706,778	2,550,667	2,672,232
Total external operating revenues	**$4,050,492**	$3,909,695	$4,176,501

	2011	2010	2009
		(In thousands)	
Intersegment operating revenues:			
Electric	**$ —**	$ —	$ —
Natural gas distribution	—	—	—
Pipeline and energy services	**67,497**	75,033	72,505
Exploration and production	**93,713**	115,784	101,230
Construction materials and contracting	**472**	—	—
Construction services	**19,471**	2,298	379
Other	**8,997**	7,580	9,487
Intersegment eliminations	**(190,150)**	(200,695)	(183,601)
Total intersegment operating revenues	**$ —**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	**$ 32,177**	$ 27,274	$ 24,637
Natural gas distribution	**44,641**	43,044	42,723
Pipeline and energy services	**25,502**	26,001	25,581
Exploration and production	**142,645**	130,455	129,922
Construction materials and contracting	**85,459**	88,331	93,615
Construction services	**11,399**	12,147	12,760
Other	**1,572**	1,591	1,304
Total depreciation, depletion and amortization	**$ 343,395**	$ 328,843	$ 330,542
Interest expense:			
Electric	**$ 13,745**	$ 12,216	$ 9,577
Natural gas distribution	**29,444**	28,996	30,656
Pipeline and energy services	**10,516**	9,064	8,896
Exploration and production	**7,445**	8,580	10,621
Construction materials and contracting	**16,241**	19,859	20,495
Construction services	**4,473**	4,411	4,490
Other	**—**	47	43
Intersegment eliminations	**(510)**	(162)	(679)
Total interest expense	**$ 81,354**	$ 83,011	$ 84,099
Income taxes:			
Electric	**$ 7,242**	$ 11,187	$ 8,205
Natural gas distribution	**16,931**	12,171	16,331
Pipeline and energy services	**12,912**	13,933	22,982

	2011	2010	2009
Exploration and production	**46,298**	49,034	(187,000)
Construction materials and contracting	**11,227**	13,822	25,940
Construction services	**13,426**	11,456	15,189
Other	**2,238**	10,927	2,261
Total income taxes	**$ 110,274**	$ 122,530	$ (96,092)
Earnings (loss) on common stock:			
Electric	**$ 29,258**	$ 28,908	$ 24,099
Natural gas distribution	**38,398**	36,944	30,796
Pipeline and energy services	**23,082**	23,208	37,845
Exploration and production	**80,282**	85,638	(296,730)
Construction materials and contracting	**26,430**	29,609	47,085
Construction services	**21,627**	17,982	25,589
Other	**6,190**	21,046	7,357
Earnings (loss) on common stock before loss from discontinued operations	**225,267**	243,335	(123,959)
Loss from discontinued operations, net of tax*	**(12,926)**	(3,361)	—
Total earnings (loss) on common stock	**$ 212,341**	$ 239,974	$ (123,959)

	2011	2010	2009
		(In thousands)	
Capital expenditures:			
Electric	**$ 52,072**	$ 85,787	$ 115,240
Natural gas distribution	**70,624**	75,365	43,820
Pipeline and energy services	**45,556**	14,255	70,168
Exploration and production	**272,855**	355,845	183,140
Construction materials and contracting	**52,303**	25,724	26,313
Construction services	**9,711**	14,849	12,814
Other	**18,759**	2,182	3,196
Net proceeds from sale or disposition of property and other	**(40,857)**	(78,761)	(26,679)
Total net capital expenditures	**$ 481,023**	$ 495,246	$ 428,012
Assets:			
Electric**	**$ 672,940**	$ 643,636	$ 569,666
Natural gas distribution**	**1,679,091**	1,632,012	1,588,144
Pipeline and energy services	**526,797**	523,075	538,230
Exploration and production	**1,481,556**	1,342,808	1,137,628
Construction materials and contracting	**1,374,026**	1,382,836	1,449,469
Construction services	**418,519**	387,627	328,895
Other***	**403,196**	391,555	378,920
Total assets	**$6,556,125**	$6,303,549	$5,990,952
Property, plant and equipment:			
Electric**	**$1,068,524**	$1,027,034	$ 941,791

Natural gas distribution**	**1,568,866**	1,508,845	1,456,208
Pipeline and energy services	**719,291**	683,807	675,199
Exploration and production	**2,615,146**	2,356,938	2,028,794
Construction materials and contracting	**1,499,852**	1,486,375	1,514,989
Construction services	**124,796**	122,940	116,236
Other	**49,747**	32,564	33,365
Less accumulated depreciation, depletion and amortization	**3,361,208**	3,103,323	2,872,465
Net property, plant and equipment	**$4,285,014**	$4,115,180	$3,894,117

* Reflected in the Other category.

** Includes allocations of common utility property.

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

Note: The results reflect a $620.0 million ($384.4 million after tax) noncash write-down of natural gas and oil properties in 2009.

Excluding the natural gas gathering arbitration charge of $16.5 million (after tax) in 2010, as discussed in Note 19, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from exploration and production, construction materials and contracting, construction services and other are all from nonregulated operations.

Capital expenditures for 2011, 2010 and 2009 include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions. The net noncash transactions were $24.0 million in 2011, $17.5 million in 2010 and immaterial in 2009.

Supplemental Financial Information (Unaudited)	12 Months Ended Dec. 31, 2011
Quarterly Financial Information Disclosure [Abstract]	
Supplementary Financial Information-Quarterly Data (Unaudited)	

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2011 and 2010:

	First Quarter	Second Quarter	Third Quarter *	Fourth Quarter **
	(In thousands, except per share amounts)			
2011				
Operating revenues	**$ 901,805**	**$ 930,757**	**$1,152,181**	**$1,065,749**
Operating expenses	**823,739**	**848,454**	**1,032,760**	**939,172**
Operating income	**78,066**	**82,303**	**119,421**	**126,577**
Income from continuing operations	**42,529**	**45,235**	**64,100**	**74,088**
Income (loss) from discontinued operations, net of tax	**448**	**(168)**	**(126)**	**(13,080)**
Net income	**42,977**	**45,067**	**63,974**	**61,008**
Earnings per common share - basic:				
Earnings before discontinued operations	**.22**	**.24**	**.34**	**.39**
Discontinued operations, net of tax	**.01**	**—**	**—**	**(.07)**
Earnings per common share - basic	**.23**	**.24**	**.34**	**.32**
Earnings per common share - diluted:				
Earnings before discontinued operations	**.22**	**.24**	**.34**	**.39**
Discontinued operations, net of tax	**.01**	**—**	**—**	**(.07)**
Earnings per common share - diluted	**.23**	**.24**	**.34**	**.32**
Weighted average common shares outstanding:				
Basic	**188,671**	**188,794**	**188,794**	**188,794**
Diluted	**188,815**	**188,968**	**188,797**	**188,932**
2010				
Operating revenues	$ 834,777	$ 906,444	$1,125,923	$1,042,551
Operating expenses	751,848	817,782	1,016,961	912,377
Operating income	82,929	88,662	108,962	130,174
Income from continuing operations	41,772	48,938	61,010	92,300
Loss from discontinued operations, net of tax	—	—	—	(3,361)

Net income	41,772	48,938	61,010	88,939
Earnings per common share - basic:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share - basic	.22	.26	.32	.47
Earnings per common share - diluted:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share - diluted	.22	.26	.32	.47
Weighted average common shares outstanding:				
Basic	187,963	188,129	188,170	188,281
Diluted	188,220	188,267	188,338	188,374

* 2010 reflects a natural gas gathering arbitration charge of $16.5 million (after tax). For more information, see Note 19.

** 2011 reflects an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract. For more information, see Note 19. 2010 reflects a $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines. For more information, see Note 4.

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

Exploration and Production Activities (Unaudited)

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

The information that follows includes Fidelity's proportionate share of all its 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:

	2011	2010	2009
		(In thousands)	
Subject to amortization	**$2,345,114**	$2,138,565	$1,815,380
Not subject to amortization	**232,462**	182,402	178,214
Total capitalized costs	**2,577,576**	2,320,967	1,993,594
Less accumulated depreciation, depletion and amortization	**1,229,654**	1,093,723	969,630

Net capitalized costs	**$1,347,922**	$1,227,244	$1,023,964

Note: Net capitalized costs 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,	**2011** *	2010 *	2009 *
		(In thousands)	
Acquisitions:			
Proved properties	**$ 3,999**	$ 89,733	$ 3,879
Unproved properties	**63,354**	92,100	8,771
Exploration	**41,775**	33,226	33,123
Development	**161,647**	139,733	135,202
Total capital expenditures	**$ 270,775**	$ 354,792	$ 180,975

* Excludes net additions/(reductions) to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of natural gas and oil wells, as discussed in Note 10, of $(1.8) million, $11.1 million and $2.0 million for the years ended December 31, 2011, 2010 and 2009, 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,	**2011**	2010	2009
		(In thousands)	
Revenues:			
Sales to affiliates	**$ 93,713**	$ 115,784	$ 101,230
Sales to external customers	**359,873**	318,565	338,425
Production costs	**140,606**	127,403	123,148
Depreciation, depletion and amortization*	**139,539**	127,266	126,278
Write-down of natural gas and oil properties	**—**	—	620,000
Pretax income	**173,441**	179,680	(429,771)
Income tax expense	**63,655**	66,293	(164,216)
Results of operations for producing activities	**$ 109,786**	$ 113,387	$ (265,555)

* Includes accretion of discount for asset retirement obligations of $3.6 million, $3.2 million and $2.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, as discussed in Note 10.

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The reserve estimates as of December 31, 2011, 2010 and 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. Other factors used in the reserve estimates are 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 are prepared by internal engineers assigned to an asset team by geographic area. Senior management reviews and approves the reserve estimates to ensure they are materially accurate. In addition, the Company engaged Ryder Scott, an independent third party, to audit its proved reserve quantity estimates.

Estimates of economically recoverable 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.

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

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	448,397	32,867	645,596
Production	(45,598)	(3,500)	(66,596)
Extensions and discoveries	28,221	6,138	65,049
Improved recovery	—	—	—
Purchases of proved reserves	54	239	1,486
Sales of proved reserves	—	—	—
Revisions of previous estimates	(51,247)	(1,397)	(59,627)
Balance at end of year	379,827	34,347	585,908

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

- Extensions and discoveries of 65.0 Bcfe primarily due to drilling activity at the Company's Bakken and Big Horn properties
- Revisions of previous estimates of (59.6) Bcfe, largely the result of a reduction in PUD reserves of 53.6 Bcfe resulting principally in the Company's Bowdoin, Baker, Coalbed, East Texas and Big Horn Basin properties. The remaining negative revisions were a reduction in PDP natural gas reserves.

The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2010, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	448,425	34,216	653,724
Production	(50,391)	(3,262)	(69,963)
Extensions and discoveries	36,191	3,389	56,523
Improved recovery	—	—	—

Purchases of proved reserves	55,119	979	60,991
Sales of proved reserves	(92)	(18)	(202)
Revisions of previous estimates	(40,855)	(2,437)	(55,477)
Balance at end of year	448,397	32,867	645,596

Significant changes in proved reserves for the year ended December 31, 2010, include:

- Extensions and discoveries of 56.5 Bcfe primarily due to drilling activity at the Company's Bakken, Baker, Bowdoin and east Texas properties
- Purchases of proved reserves of 61.0 Bcfe as a result of the Company's acquisition of natural gas properties in the Green River Basin in Wyoming, as discussed in Note 2
- Revisions of previous estimates of (55.5) Bcfe largely the result of negative performance revisions resulting primarily from new information gained from production history and developmental drilling activity in the Company's Bowdoin, south Texas, Baker and east Texas properties and removal of PUD reserves due to the five-year limitation rule, partially offset by positive revisions due to increased natural gas and oil prices

The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2009, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	604,282	34,348	810,371
Production	(56,632)	(3,111)	(75,299)
Extensions and discoveries	26,882	2,569	42,297
Improved recovery	—	—	—
Purchases of proved reserves	—	—	—
Sales of proved reserves	(22)	(248)	(1,510)
Revisions of previous estimates	(126,085)	658	(122,135)
Balance at end of year	448,425	34,216	653,724

Significant changes in proved reserves for the year ended December 31, 2009, include:

- Extensions and discoveries of 42.3 Bcfe primarily due to drilling activity at the Company's Bowdoin, Bakken, Baker and east Texas properties
- Revisions of previous estimates of (122.1) Bcfe largely the result of negative revisions resulting from decreased natural gas and oil prices and negative performance revisions resulting primarily from new information gained from production history and developmental drilling activity in the Company's east Texas and south Texas properties

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

	2011	2010	2009
Proved developed reserves:			
Natural Gas (MMcf)	**303,495**	334,911	321,561
Oil (MBbls)	**28,878**	26,586	26,794

Total (MMcfe)	**476,763**	494,426	482,329
PUD reserves:			
Natural Gas (MMcf)	**76,332**	113,486	126,864
Oil (MBbls)	**5,469**	6,281	7,422
Total (MMcfe)	**109,145**	151,170	171,395
Total proved reserves:			
Natural Gas (MMcf)	**379,827**	448,397	448,425
Oil (MBbls)	**34,347**	32,867	34,216
Total (MMcfe)	**585,908**	645,596	653,724

As of December 31, 2011, the Company had 109.1 Bcfe of PUD reserves, which is a decrease of 42.0 Bcfe from December 31, 2010. The decrease relates to the Company converting 27.1 Bcfe of its December 31, 2010, PUD reserves into proved developed reserves in 2011, requiring $62.9 million of drilling and completion capital and 53.6 Bcfe of negative revisions applied to PUD locations primarily in the Company's natural gas properties. These changes were partially offset by 38.7 Bcfe of new PUD reserves primarily in the Company's oil properties. At December 31, 2011, the Company did not have any PUD locations that remained undeveloped for five years or more. Future development costs estimated to be spent in each of the next three years to develop PUD reserves as of December 31, 2011, are $109.3 million in 2012, $47.8 million in 2013 and $13.7 million in 2014.

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:

	2011	2010	2009
	(In thousands)		
Future cash inflows	**$4,188,000**	$3,790,700	$2,991,200
Future production costs	**1,560,300**	1,393,000	1,095,600
Future development costs	**285,300**	312,500	315,000
Future net cash flows before income taxes	**2,342,400**	2,085,200	1,580,600
Future income tax expense	**531,100**	432,800	291,000
Future net cash flows	**1,811,300**	1,652,400	1,289,600
10% annual discount for estimated timing of cash flows	**832,500**	756,300	630,800
Discounted future net cash flows relating to proved natural gas and oil reserves	**$ 978,800**	$ 896,100	$ 658,800

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

	2011	2010	2009
	(In thousands)		
Beginning of year	**$ 896,100**	$ 658,800	$ 969,800
Net revenues from production	**(301,500)**	(270,000)	(200,900)
Net change in sales prices and production costs related to future production	**82,300**	362,400	(364,800)

Extensions and discoveries, net of future production-related costs	**226,300**	130,500	70,500
Improved recovery, net of future production-related costs	**—**	—	—
Purchases of proved reserves, net of future production-related costs	**9,500**	99,800	—
Sales of proved reserves	**—**	(500)	(1,100)
Changes in estimated future development costs	**51,100**	34,100	43,600
Development costs incurred during the current year	**56,300**	43,100	46,400
Accretion of discount	**105,000**	76,500	115,900
Net change in income taxes	**(55,800)**	(103,300)	142,800
Revisions of previous estimates	**(92,900)**	(132,000)	(155,500)
Other	**2,400**	(3,300)	(7,900)
Net change	**82,700**	237,300	(311,000)
End of year	**$ 978,800**	$ 896,100	$ 658,800

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 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.

Supplemental Financial Information Exploration and Production (Details 4) (Details)	12 Months Ended Dec. 31, 2011 Mcfe	Dec. 31, 2010 Mcfe	Dec. 31, 2009 Mcfe
Proved Developed and Undeveloped Reserves [Roll Forward]			
Proved developed and undeveloped reserves, starting balance	645,596,000	653,724,000	810,371,000
Proved Developed and Undeveloped Reserves, Production	(66,596,000)	(69,963,000)	(75,299,000)
Proved Developed and Undeveloped Reserves, Extensions, Discoveries, and Additions	65,049,000	56,523,000	42,297,000
Proved Developed and Undeveloped Reserves, Improved Recovery	0	0	0
Proved Developed and Undeveloped Reserves, Purchases of Minerals in Place	1,486,000	60,991,000	0
Proved Developed and Undeveloped Reserves, Sales of Minerals in Place	0	(202,000)	(1,510,000)
Proved Developed and Undeveloped Reserves, Revisions of Previous Estimates	(59,627,000)	(55,477,000)	(122,135,000)
Proved developed and undeveloped reserves, ending balance	585,908,000	645,596,000	653,724,000
Reduction in proved undeveloped reserves	53,600,000		
Natural Gas Reserves [Member]			
Proved Developed and Undeveloped Reserves [Roll Forward]			
Proved developed and undeveloped reserves, starting balance	448,397	448,425	604,282
Proved Developed and Undeveloped Reserves, Production	(45,598)	(50,391)	(56,632)
Proved Developed and Undeveloped Reserves, Extensions, Discoveries, and Additions	28,221	36,191	26,882
Proved Developed and Undeveloped Reserves, Improved Recovery	0	0	0
Proved Developed and Undeveloped Reserves, Purchases of Minerals in Place	54	55,119	0
Proved Developed and Undeveloped Reserves, Sales of Minerals in Place	0	(92)	(22)
Proved Developed and Undeveloped Reserves, Revisions of Previous Estimates	(51,247)	(40,855)	(126,085)
Proved developed and undeveloped reserves, ending balance	379,827	448,397	448,425
Oil Reserves [Member]			
Proved Developed and Undeveloped Reserves [Roll Forward]			
Proved developed and undeveloped reserves, starting balance	32,867	34,216	34,348
Proved Developed and Undeveloped Reserves, Production	(3,500)	(3,262)	(3,111)
Proved Developed and Undeveloped Reserves, Extensions, Discoveries, and Additions	6,138	3,389	2,569
Proved Developed and Undeveloped Reserves, Improved Recovery	0	0	0
Proved Developed and Undeveloped Reserves, Purchases of Minerals in Place	239	979	0
Proved Developed and Undeveloped Reserves, Sales of Minerals in Place	0	(18)	(248)
Proved Developed and Undeveloped Reserves, Revisions of Previous Estimates	(1,397)	(2,437)	658

Proved developed and undeveloped reserves, ending balance	34,347	32,867	34,216

Summary of Significant Accounting Policies (Details 6) In Thousands, unless otherwise specified	3 Months Ended								12 Months Ended		
	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2010	Jun. 30, 2010	Mar. 31, 2010	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Earnings (loss) per common share [Abstract]											
Weighted average common shares outstanding - basic	188,794	188,794	188,794	188,671	188,281	188,170	188,129	187,963	188,763	188,137	185,175 [1]
Effect of dilutive stock options and performance share awards (in shares)									142	92	0 [1]
Weighted Average Common Shares Outstanding - Diluted	188,932	188,797	188,968	188,815	188,374	188,338	188,267	188,220	188,905	188,229	185,175 [1]
Stock Options [Member]											
Earnings (loss) per common share [Abstract]											
Antidilutive securities excluded from computation of diluted loss per common share (in shares)											825
Restricted Stock [Member]											
Earnings (loss) per common share [Abstract]											
Antidilutive securities excluded from computation of diluted loss per common share (in shares)											18
Performance Share Awards [Member]											
Earnings (loss) per common share [Abstract]											
Antidilutive securities excluded from computation of diluted loss per common share (in shares)											656

[1] Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.

Employee Benefit Plans (Tables)	12 Months Ended Dec. 31, 2011

Compensation and Retirement Disclosure [Abstract]

Changes in benefit obligation and plan assets

Changes in benefit obligation and plan assets for the years ended December 31, 2011 and 2010, and amounts recognized in the Consolidated Balance Sheets at December 31, 2011 and 2010, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 388,589**	$ 352,915	**$ 91,286**	$ 88,151
Service cost	**2,252**	2,889	**1,443**	1,357
Interest cost	**19,500**	19,761	**4,700**	4,817
Plan participants' contributions	**—**	—	**2,644**	2,500
Amendments	**—**	353	**—**	121
Actuarial loss	**62,722**	34,687	**17,940**	3,228
Curtailment gain	**(13,939)**	—	**—**	—
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Benefit obligation at end of year	**435,618**	388,589	**110,689**	91,286
Change in net plan assets:				
Fair value of plan assets at beginning of year	**277,598**	255,327	**70,610**	66,984
Actual gain (loss) on plan assets	**(4,718)**	37,853	**(872)**	7,278
Employer contribution	**28,626**	6,434	**3,027**	2,736
Plan participants' contributions	**—**	—	**2,644**	2,500
Benefits paid	**(23,506)**	(22,016)	**(7,324)**	(8,888)
Fair value of net plan assets at end of year	**278,000**	277,598	**68,085**	70,610
Funded status - under	**$ (157,618)**	$ (110,991)	**$ (42,604)**	$ (20,676)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	**$ —**	$ —	**$ (550)**	$ (525)
Other liabilities (noncurrent)	**(157,618)**	(110,991)	**(42,054)**	(20,151)
Net amount recognized	**$ (157,618)**	$ (110,991)	**$ (42,604)**	$ (20,676)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 189,494**	$ 117,840	**$ 43,861**	$ 20,751
Prior service cost (credit)	**(632)**	631	**(8,615)**	(11,292)
Transition obligation	**—**	—	**2,128**	4,253
Total	**$ 188,862**	$ 118,471	**$ 37,374**	$ 13,712

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

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:

	2011	2010
	(In thousands)	
Projected benefit obligation	**$ 435,618**	$ 388,589
Accumulated benefit obligation	**$ 435,618**	$ 374,538
Fair value of plan assets	**$ 278,000**	$ 277,598

Components of net periodic benefit cost

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		
	2011	2010	2009	**2011**	2010	2009
	(In thousands)					

Components of net periodic benefit cost:						
Service cost	**$ 2,252**	$ 2,889	$ 8,127	**$ 1,443**	$ 1,357	$ 2,206
Interest cost	**19,500**	19,761	21,919	**4,700**	4,817	5,465
Expected return on assets	**(22,809)**	(23,643)	(25,062)	**(5,051)**	(5,512)	(5,471)
Amortization of prior service cost (credit)	**45**	152	605	**(2,677)**	(3,303)	(2,756)
Recognized net actuarial loss	**4,656**	2,622	2,096	**753**	845	970
Curtailment loss	**1,218**	—	1,650	**—**	—	—
Amortization of net transition obligation	**—**	—	—	**2,125**	2,125	2,125
Net periodic benefit cost, including amount capitalized	**4,862**	1,781	9,335	**1,293**	329	2,539
Less amount capitalized	**1,196**	791	1,127	**(50)**	(92)	330
Net periodic benefit cost	**3,666**	990	8,208	**1,343**	421	2,209
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**76,310**	20,477	(29,000)	**23,863**	1,462	(2,314)
Prior service cost (credit)	**—**	353	—	**—**	121	(9,321)
Amortization of actuarial loss	**(4,656)**	(2,622)	(2,096)	**(753)**	(845)	(970)
Amortization of prior service (cost) credit	**(1,263)**	(152)	(2,255)	**2,677**	3,303	2,756
Amortization of net transition obligation	**—**	—	—	**(2,125)**	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	**70,391**	18,056	(33,351)	**23,662**	1,916	(11,974)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	**$ 74,057**	$ 19,046	$ (25,143)	**$ 25,005**	$ 2,337	$ (9,765)

Weighted average assumptions used to determine benefit obligations and net periodic benefit costs

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

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
Discount rate	**4.16%**	5.26%	**4.13%**	5.21%
Expected return on plan assets	**7.75%**	7.75%	**6.75%**	6.75%
Rate of compensation increase	**N/A**	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	
	2011	2010	**2011**	2010
Discount rate	**5.26%**	5.75%	**5.21%**	5.75%
Expected return on plan assets	**7.75%**	8.25%	**6.75%**	7.25%
Rate of compensation increase	**% / 4.00N/A ***	4.00%	**4.00%**	4.00%

* Effective June 30, 2011, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.

Health care rate assumptions for the Company's other postretirement benefit plans

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

	2011	2010
Health care trend rate assumed for next year	**6.0% - 8.0%**	6.0% - 8.5%
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

Assumed health care cost trend rates

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, 2011:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 171	$ (822)
Effect on postretirement benefit obligation	$ 3,175	$ (10,946)

The fair value of the Company's pension net plan assets by class

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

	Fair Value Measurements at December 31, 2011, 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, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 2,256	$ 17,534	$ —	$ 19,790
Equity securities:				
U.S. companies	99,315	—	—	99,315
International companies	35,353	—	—	35,353
Collective and mutual funds (a)	43,214	15,541	—	58,755
Corporate bonds	—	23,579	289	23,868
Mortgage-backed securities	—	22,987	—	22,987
Municipal bonds	—	9,290	—	9,290
U.S. Treasury securities	—	8,642	—	8,642
Total assets measured at fair value	$ 180,138	$ 97,573	$ 289	$ 278,000

(a) Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.

	Fair Value Measurements at December 31, 2010, 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, 2010
	(In thousands)			
Assets:				
Cash equivalents	$ 4,663	$ 8,699	$ —	$ 13,362
Equity securities:				
U.S. companies	102,944	—	—	102,944
International companies	40,017	—	—	40,017
Collective and mutual funds (a)	45,410	17,701	—	63,111
Collateral held on loaned securities (b)	—	23,148	694	23,842
Corporate bonds	—	23,014	—	23,014
Mortgage-backed securities	—	19,478	—	19,478
U.S. Treasury securities	—	9,239	—	9,239
Municipal bonds	—	8,285	—	8,285
Total assets measured at fair value	193,034	109,564	694	303,292
Liabilities:				
Obligation for collateral received	25,694	—	—	25,694
Net assets measured at fair value	$ 167,340	$ 109,564	$ 694	$ 277,598

(a) Collective and mutual funds invest approximately 28 percent in common stock of mid-cap U.S. companies, 24 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 11 percent in mortgage-backed securities, 10 percent in corporate bonds, 8 percent in foreign fixed-income investments and 6 percent in common stock of small-cap U.S. companies.

(b) This class includes collateral held at December 31, 2010, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, mutual funds and commercial paper.

Summary of changes in the fair value of the pension plan's Level 3 assets

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, 2011:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
	(In thousands)		
Balance at beginning of year	$ —	$ 694	$ 694
Total realized/unrealized losses	(2)	(259)	(261)
Purchases, issuances and settlements (net)	291	(435)	(144)
Balance at end of year	$ 289	$ —	$ 289

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, 2010:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Collateral Held on Loaned Securities
	(In thousands)
Balance at beginning of year	$ 937
Total realized/unrealized losses	189
Purchases, issuances and settlements (net)	(432)
Balance at end of year	$ 694

Fair value of other postretirement benefit plan assets by asset class

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

	Fair Value Measurements at December 31, 2011, 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, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 59	$ 1,836	$ —	$ 1,895
Equity securities:				
U.S. companies	2,098	—	—	2,098
International companies	262	—	—	262
Insurance investment contract*	—	63,830	—	63,830
Total assets measured at fair value	$ 2,419	$ 65,666	$ —	$ 68,085

* The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010

	(Level 1)			
		(In thousands)		
Assets:				
Cash equivalents	$ 53	$ 1,274	$ —	$ 1,327
Equity securities:				
U.S. companies	2,791	—	—	2,791
International companies	353	—	—	353
Insurance investment contract*	—	66,139	—	66,139
Total assets measured at fair value	$ 3,197	$ 67,413	$ —	$ 70,610

* The insurance investment contract invests approximately 53 percent in common stock of large-cap U.S. companies, 21 percent in corporate bonds, 12 percent in mortgage-backed securities and 14 percent in other investments.

Benefit payments expected to be paid

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2012	$ 22,426	$ 6,892	$ 618
2013	22,811	7,062	656
2014	23,082	7,188	694
2015	23,508	7,298	730
2016	23,893	7,371	766
2017 - 2021	127,895	37,682	4,322

Schedule of Multiemployer Plans [Table Text Block]

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status		FIP/RP Status Pending/ Implemented	Contributions			Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
		2011	2010		**2011**	2010	2009		
						(In thousands)			
Edison Pension Plan	93-6061681-001	Green	Green	No	**$ 2,700**	$ 1,933	$ 1,627	No	12/31/2012
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**1,469**	1,277	594	No	*
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2011	Red as of 6/30/2010	Implemented	**1,331**	1,569	1,197	No	*
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2011	Red as of 2/28/2010	Implemented	**722**	781	641	No	8/31/2012
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2011	Yellow as of 5/31/2010	Implemented	**628**	413	325	No	6/30/2012*
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	**776**	679	469	No	*
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**4,841**	4,826	5,462	No	5/31/2014*
OE Pension Trust Fund	94-6090764-001	Yellow	Yellow	Implemented	**1,367**	1,035	1,061	No	3/31/2016*
Other funds					**15,324**	17,763	21,103		
Total contributions					**$ 29,158**	$ 30,276	$ 32,479		

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

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

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Defined Benefit Pension Plan of AGC-IUOE Local 701 Pension Trust Fund	2010 and 2009
Edison Pension Plan	2010 and 2009
Eighth District Electrical Pension Fund	2010 and 2009
IBEW Local 38 Pension Plan	2010 and 2009

IBEW Local No. 82 Pension Plan	2010 and 2009
IBEW Local Union No. 357 Pension Plan A	2010 and 2009
IBEW Local 648 Pension Plan	2010 and 2009
Idaho Plumbers and Pipefitters Pension Plan	2010 and 2009
Laborers AGC Pension Trust of Montana	2009
Local Union No. 124 IBEW Pension Trust Fund	2010 and 2009
Local Union 212 IBEW Pension Trust Fund	2010 and 2009
Minnesota Teamsters Constr Division Pension Fund	2010 and 2009
Operating Engineers Local 800 and Wyoming Contractors Association, Inc. Pension Plan for Wyoming	2010 and 2009
Plumbers & Pipefitters Local 162 Pension Fund	2010 and 2009
Southwest Marine Pension Trust	2009

Consolidated Statements of Cash Flows (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Operating activities:			
Net income (loss)	$ 213,026,000	$ 240,659,000	$ (123,274,000)
Income (loss) from discontinued operations, net of tax	(12,926,000) [1]	(3,361,000) [1]	0 [1]
Income (loss) from continuing operations	225,952,000	244,020,000	(123,274,000)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	343,395,000	328,843,000	330,542,000
Earnings, net of distributions, from equity method investments	(2,111,000)	(26,158,000)	(3,018,000)
Deferred income taxes	118,925,000	66,585,000	(169,764,000)
Noncash write-down of natural gas and oil properties	0	0	620,000,000
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(30,452,000)	(59,037,000)	132,939,000
Inventories	(24,226,000)	(4,728,000)	13,969,000
Other current assets	7,729,000	(7,424,000)	67,803,000
Accounts payable	(12,263,000)	17,833,000	(61,867,000)
Other current liabilities	33,738,000	12,289,000	44,039,000
Other noncurrent changes	(33,365,000)	(20,271,000)	(4,683,000)
Net cash provided by continuing operations	627,322,000	551,952,000	846,686,000
Net cash used in discontinued operations	(674,000)	(319,000)	0
Net cash provided by operating activities	626,648,000	551,633,000	846,686,000
Investing activities:			
Capital expenditures	(497,000,000)	(449,282,000)	(448,675,000)
Acquisitions, net of cash acquired	(157,000)	(104,812,000)	(6,410,000)
Net proceeds from sale or disposition of property and other	40,107,000	76,386,000	26,679,000
Investments	(10,302,000)	704,000	(3,740,000)
Proceeds from sale of equity method investments	2,807,000	69,060,000	0
Net cash used in continuing operations	(464,545,000)	(407,944,000)	(432,146,000)
Net cash provided by discontinued operations	0	0	0
Net cash used in investing activities	(464,545,000)	(407,944,000)	(432,146,000)
Financing activities:			
Issuance of short-term borrowings	0	20,000,000	10,300,000
Repayment of short-term borrowings	(20,000,000)	(10,300,000)	(105,100,000)
Issuance of long-term debt	300,000	20,200,000	145,000,000
Repayment of long-term debt	(85,151,000)	(13,668,000)	(292,907,000)
Proceeds from issuance of common stock	5,744,000	4,972,000	65,207,000
Dividends paid	(123,323,000)	(119,157,000)	(115,023,000)
Excess tax benefit on stock-based compensation	1,239,000	1,186,000	601,000
Net cash used in continuing operations	(221,191,000)	(96,767,000)	(291,922,000)

Net cash provided by discontinued operations	0	0	0
Net cash used in financing activities	(221,191,000)	(96,767,000)	(291,922,000)
Effect of exchange rate changes on cash and cash equivalents	(214,000)	38,000	782,000
Increase (decrease) in cash and cash equivalents	(59,302,000)	46,960,000	123,400,000
Cash and cash equivalents - beginning of year	222,074,000	175,114,000	51,714,000
Cash and cash equivalents - end of year	$ 162,772,000	$ 222,074,000	$ 175,114,000

[1] Reflected in the Other category.

Commitments and Contingencies (Details 3) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Operating Leases, Annual minimum lease payments due [Abstract]			
2012	$ 27,800,000		
2013	24,300,000		
2014	16,400,000		
2015	8,600,000		
2016	5,800,000		
Thereafter	35,900,000		
Rent expense			
Rent expense	$ 40,700,000	$ 38,700,000	$ 43,400,000

Equity Method Investments	12 Months Ended Dec. 31, 2011
Equity Method Investments and Joint Ventures [Abstract]	
Equity Method Investments	

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, 2011 and 2010, include ECTE.

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

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale and recognized a gain of $22.7 million ($13.8 million after tax). The Company's entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE was sold. The remaining interest in ECTE is being purchased by one of the parties over a four-year period. In November 2011, the Company completed the sale of one-fourth of the remaining interest and recognized a gain of $1.0 million ($600,000 after tax). The gains are recorded in earnings from equity method investments on the Consolidated Statements of Income. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE.

At December 31, 2011 and 2010, the Company's equity method investments had total assets of $111.1 million and $107.4 million, respectively, and long-term debt of $37.1 million and $30.1 million, respectively. The Company's investment in its equity method investments was approximately $9.2 million and $10.9 million, including undistributed earnings of $3.7 million and $1.9 million, at December 31, 2011 and 2010, respectively.

Derivative Instruments (Details) (USD $)	12 Months Ended Dec. 31, 2011 MMBTU bbl	Dec. 31, 2010
Derivative Instruments [Line Items]		
Natural gas swap agreement with total foward notional volumes	305,000	
Change In Fair Value Of Derivative Instruments Not Designated As Hedging Instruments Recorded As Increase Decrease To Regulatory Assets	$ 8,900,000	$ 18,500,000
Aggregate fair value of Assets Needed for Immediate Settlement if credit-risk related contingent features were triggered	437,000	
Derivative instruments with credit-risk-related contingent features, net liability position, aggregate fair value	437,000	
Nonmonetary Notional Forward Amount of natural gas swap, collar and/or put agreements in MMBtu, Derivative Instruments Designated as cash flow hedging Instruments	10,800,000	
Notional Forward Amount Of Cash Flow Hedge Instruments Natural Gas Basis Swaps	3,500,000	
Notional Forward Amount Of Cash Flow Hedge Instruments Oil Swaps And Collars	4,000,000	
Notional Amount of Derivatives	60,000,000	
Maximum length of time hedged in swap, collar and/or put cash flow hedge agreements (in months)	24	
Amount of Hedge Ineffectiveness	1,800,000	
Cash flow hedge gain (loss) to be reclassified within twelve months from AOCI into earnings	8,700,000	
Derivative Net Liability Position Aggregate Fair Value For Cash Flow Hedging Instruments	18,400,000	
Assets Needed For Immediate Settlement Aggregate Fair Value For Cash Flow Hedging Instruments	$ 18,400,000	

Employee Benefit Plans Multiemployer Pension Plan (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Multiemployer Plans [Line Items]			
Multiemployer plan red zone status funded percentage, maximum	65.00%		
Multiemployer plan yellow zone status funded percentage, minimum	65.00%		
Mulitiemployer plan yellow status funded percentage, maximum	80.00%		
Multiemployer plan green zone status funded percentage, minimum	80.00%		
Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plan, Period Contributions	$ 29,158	$ 30,276	$ 32,479
Multiemployer Plans, Postretirement Benefit [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plan, Period Contributions	24,000	24,700	28,900
Multiemployer Plans, Defined Contribution [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plan, Period Contributions	15,300	15,400	16,400
Edison Pension Plan [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plans, Surcharge	no		
Multiemployer Plans, Collective-Bargaining Arrangement, Expiration Date	Dec. 31, 2012		
Edison Pension Plan [Member] | Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Entity Tax Identification Number	936061681		
Multiemployer Plan Number	001		
Multiemployer Plans, Certified Zone Status	green	green	
Multiemployer Plans, Funding Improvement Plan and Rehabilitation Plan	no		
Multiemployer Plan, Period Contributions	2,700	1,933	1,627
IBEW Local 38 Pension Plan [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plans, Surcharge	no		
IBEW Local 38 Pension Plan [Member] | Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Entity Tax Identification Number	346574238		
Multiemployer Plan Number	001		
Multiemployer Plans, Certified Zone Status	yellow	yellow	
Multiemployer Plans, Certified Zone Status, Date	Apr. 30, 2011	Apr. 30, 2010	
Multiemployer Plans, Funding Improvement Plan and Rehabilitation Plan	implemented		
Multiemployer Plan, Period Contributions	1,469	1,277	594

IBEW Local No. 82 Pension Plan [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plans, Surcharge	no		
IBEW Local No. 82 Pension Plan [Member] | Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Entity Tax Identification Number	316127268		
Multiemployer Plan Number	001		
Multiemployer Plans, Certified Zone Status	red	red	
Multiemployer Plans, Certified Zone Status, Date	Jun. 30, 2011	Jun. 30, 2010	
Multiemployer Plans, Funding Improvement Plan and Rehabilitation Plan	implemented		
Multiemployer Plan, Period Contributions	1,331	1,569	1,197
IBEW Local 648 Pension Plan [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plans, Surcharge	no		
Multiemployer Plans, Collective-Bargaining Arrangement, Expiration Date	Aug. 31, 2012		
IBEW Local 648 Pension Plan [Member] | Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Entity Tax Identification Number	316134845		
Multiemployer Plan Number	001		
Multiemployer Plans, Certified Zone Status	red	red	
Multiemployer Plans, Certified Zone Status, Date	Feb. 28, 2011	Feb. 28, 2010	
Multiemployer Plans, Funding Improvement Plan and Rehabilitation Plan	implemented		
Multiemployer Plan, Period Contributions	722	781	641
Laborers Pension Trust Fund for Northern California [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plans, Surcharge	no		
Multiemployer Plans, Collective-Bargaining Arrangement, Expiration Date	Jun. 30, 2012		
Laborers Pension Trust Fund for Northern California [Member] | Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Entity Tax Identification Number	946277608		
Multiemployer Plan Number	001		
Multiemployer Plans, Certified Zone Status	yellow	yellow	
Multiemployer Plans, Certified Zone Status, Date	May 31, 2011	May 31, 2010	
Multiemployer Plans, Funding Improvement Plan and Rehabilitation Plan	implemented		
Multiemployer Plan, Period Contributions	628	413	325
Local Union 212 IBEW Pension Trust Fund [Member]			
Multiemployer Plans [Line Items]			

Multiemployer Plans, Surcharge	no		
Local Union 212 IBEW Pension Trust Fund [Member] | Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Entity Tax Identification Number	316127280		
Multiemployer Plan Number	001		
Multiemployer Plans, Certified Zone Status	yellow	yellow	
Multiemployer Plans, Certified Zone Status, Date	Apr. 30, 2011	Apr. 30, 2010	
Multiemployer Plans, Funding Improvement Plan and Rehabilitation Plan	implemented		
Multiemployer Plan, Period Contributions	776	679	469
National Electrical Benefit Fund [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plans, Surcharge	no		
Multiemployer Plans, Collective-Bargaining Arrangement, Expiration Date	May 31, 2014		
National Electrical Benefit Fund [Member] | Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Entity Tax Identification Number	530181657		
Multiemployer Plan Number	001		
Multiemployer Plans, Certified Zone Status	green	green	
Multiemployer Plans, Funding Improvement Plan and Rehabilitation Plan	no		
Multiemployer Plan, Period Contributions	4,841	4,826	5,462
OE Pension Trust Fund [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plans, Surcharge	no		
Multiemployer Plans, Collective-Bargaining Arrangement, Expiration Date	Mar. 31, 2016		
OE Pension Trust Fund [Member] | Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Entity Tax Identification Number	946090764		
Multiemployer Plan Number	001		
Multiemployer Plans, Certified Zone Status	yellow	yellow	
Multiemployer Plans, Funding Improvement Plan and Rehabilitation Plan	implemented		
Multiemployer Plan, Period Contributions	1,367	1,035	1,061
Multiemployer Plan, Individually Insignificant Multiemployer Plans [Member] | Multiemployer Plans, Pension [Member]			
Multiemployer Plans [Line Items]			
Multiemployer Plan, Period Contributions	$ 15,324	$ 17,763	$ 21,103

Income Taxes (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
United States	$ 333,486	$ 336,450	$ (227,021)
Foreign	2,740	30,100	7,655
Income (loss) before income taxes	$ 336,226	$ 366,550	$ (219,366)

Schedule I-Condensed Financial Information of Registrant	12 Months Ended Dec. 31, 2011
Condensed Financial Information of Parent Company Only Disclosure [Abstract]	
Schedule I-Condensed Financial Information of Registrant	***Summary of Significant Accounting Policies*** *Basis of presentation* The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, which is comprised of MDU Resources Group, Inc. (the Company) and Montana-Dakota and Great Plains, public utility divisions of the Company. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income from subsidiaries is reported as equity in earnings of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. In Schedule I, amounts from discontinued operations have not been separately stated. These statements should be read in conjunction with the consolidated financial statements and notes thereto of MDU Resources Group, Inc. *Earnings (loss) per common share* Please refer to the Consolidated Statements of Income of the registrant for earnings (loss) per common share. In addition, see Note 1 of Notes to Consolidated Financial Statements for information on the computation of earnings (loss) per common share. ***Note 2 - Debt*** The Company has long-term debt obligations outstanding of $280.9 million at December 31, 2011, with annual maturities of $100,000 from 2012 to 2015, $50.0 million in 2016 and $230.5 million scheduled to mature in years after 2016. For more information on debt, see Note 9 of Notes to Consolidated Financial Statements. ***Note 3 - Dividends*** The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $96.1 million, $96.4 million and $116.3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Income Taxes (Details 6) (USD $)	12 Months Ended		
	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2009
Reconciliation of Unrecognized Tax Benefits, Excluding Amounts Pertaining to Examined Tax Returns [Roll Forward]			
Balance at beginning of year	$ 9,378,000	$ 6,148,000	$ 5,586,000
Additions based on tax positions related to the prior years	4,172,000	3,230,000	562,000
Unrecognized Tax Benefits, Decreases Resulting from Settlements with Taxing Authorities	(2,344,000)	0	0
Balance at end of year	11,206,000	9,378,000	6,148,000
Unrecognized tax benefits highly certain deductibility	6,600,000	3,800,000	
Unrecognized tax benefits that would affect the effective tax rate	6,000,000	7,100,000	
Unrecognized tax benefits, interest and penalties	1,400,000	1,500,000	
Interest expense	780,000	2,000,000	190,000
Interest income	1,900,000	20,000	165,000
Accrued liability for payment of interest	$ 970,000	$ 2,300,000	

Stock-Based Compensation (Tables)	12 Months Ended Dec. 31, 2011
Share-based Compensation [Abstract]	
A summary of the status of the stock option plans and changes during the year	A summary of the status of the stock option plans at December 31, 2011, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	440,984	$13.34
Forfeited	(3,893)	13.22
Exercised	(430,341)	13.34
Balance at end of year	6,750	13.03
Exercisable at end of year	6,750	$13.03

Target grants performance share

Target grants of performance shares outstanding at December 31, 2011, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2009	2009-2011	257,836
March 2010	2010-2012	227,009
February 2011	2011-2013	277,309

Schedule of Share-based Payment Award, Stock Options, Valuation Assumptions

Assumptions used for grants of performance shares issued in 2011, 2010 and 2009 were:

			2011			2010			2009
Grant-date fair value			**$19.99**			$17.40			$20.39
Blended volatility range	**23.20%**	-	**32.18%**	25.69%	-	35.36%	40.40%	-	50.98%
Risk-free interest rate range	**.09%**	-	**1.34%**	.13%	-	1.45%	.30%	-	1.36%
Discounted dividends per share			**$1.23**			$1.04			$1.79

A summary of the status of the performance share awards

A summary of the status of the performance share awards for the year ended December 31, 2011, was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	669,685	$	22.19
Granted	278,252		19.99
Vested	—		—
Forfeited	(185,783)		30.55
Nonvested at end of period	762,154	$	19.35

Income Taxes	12 Months Ended Dec. 31, 2011

Income Tax Disclosure [Abstract]

Income Taxes

Income Taxes

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

	2011	2010	2009
	(In thousands)		
United States	**$ 333,486**	$ 336,450	$ (227,021)
Foreign	**2,740**	30,100	7,655
Income (loss) before income taxes from continuing operations	**$ 336,226**	$ 366,550	$ (219,366)

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

	2011	2010	2009
	(In thousands)		
Current:			
Federal	**$ (7,188)**	$ 37,014	$ 64,389
State	**778**	10,589	8,284
Foreign	**127**	4,451	254
	(6,283)	52,054	72,927
Deferred:			
Income taxes -			
Federal	**105,528**	62,618	(147,607)
State	**13,157**	4,147	(22,370)
Investment tax credit - net	**240**	(180)	213
	118,925	66,585	(169,764)
Change in uncertain tax benefits	**(1,048)**	3,230	562
Change in accrued interest	**(1,320)**	661	183
Total income tax expense (benefit)	**$ 110,274**	$ 122,530	$ (96,092)

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

	2011	2010
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 119,189**	$ 114,427
Accrued pension costs	**95,260**	82,085
Asset retirement obligations	**26,380**	24,391
Legal and environmental contingencies	**21,788**	13,622

Compensation-related	**16,241**	17,261
Other	**41,055**	40,307
Total deferred tax assets	**319,913**	292,093
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**715,482**	679,809
Basis differences on natural gas and oil producing properties	**210,146**	152,455
Regulatory matters	**84,963**	64,017
Intangible asset amortization	**14,307**	14,843
Other	**23,774**	20,348
Total deferred tax liabilities	**1,048,672**	931,472
Net deferred income tax liability	**$ (728,759)**	$ (639,379)

As of December 31, 2011 and 2010, no valuation allowance has been recorded associated with the previously identified deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2010, to December 31, 2011, to deferred income tax expense:

	2011
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 89,380**
Deferred taxes associated with other comprehensive loss	**9,678**
Deferred taxes associated with discontinued operations	**8,090**
Other	**11,777**
Deferred income tax expense for the period	**$ 118,925**

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,	**2011**		2010		2009	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	**$117,679**	**35.0**	$128,293	35.0	$ (76,778)	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	**10,653**	**3.2**	10,210	2.8	(7,280)	3.3
Resolution of tax matters and uncertain tax positions	**(3,906)**	**(1.2)**	667	.2	881	(.4)

Federal renewable energy credit	**(3,485)**	**(1.0)**	(2,185)	(.6)	(1,452)	.7
Depletion allowance	**(3,266)**	**(1.0)**	(2,810)	(.8)	(2,320)	1.0
Deductible K-Plan dividends	**(2,282)**	**(.7)**	(2,309)	(.6)	(2,369)	1.1
Foreign operations	**(391)**	**(.1)**	(588)	(.2)	(1,148)	.5
Domestic production activities deduction	**—**	**—**	—	—	(856)	.4
Other	**(4,728)**	**(1.4)**	(8,748)	(2.4)	(4,770)	2.2
Total income tax expense (benefit)	**$110,274**	**32.8**	$122,530	33.4	$ (96,092)	43.8

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.

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $6.9 million at December 31, 2011. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2011, was approximately $1.6 million.

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

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

	2011	2010	2009
		(In thousands)	
Balance at beginning of year	**$ 9,378**	$ 6,148	$ 5,586
Additions for tax positions of prior years	**4,172**	3,230	562
Settlements	**(2,344)**	—	—
Balance at end of year	**$ 11,206**	$ 9,378	$ 6,148

Included in the balance of unrecognized tax benefits at December 31, 2011 and 2010, were $6.6 million and $3.8 million, respectively, of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $6.0 million, including approximately $1.4 million for the payment of interest and penalties at December 31, 2011, and was $7.1 million, including approximately $1.5 million for the payment of interest and penalties at December 31, 2010.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2011, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2011, 2010 and 2009, the Company recognized approximately $780,000, $2.0 million and $190,000, respectively, in interest expense. Penalties were not material in 2011, 2010 and 2009. The Company recognized interest income of approximately $1.9 million, $20,000 and $165,000 for the years ended December 31, 2011, 2010 and 2009, respectively. The Company had accrued liabilities of approximately $970,000 and $2.3 million at December 31, 2011 and 2010, respectively, for the payment of interest.