

YEAR ENDING 2009

ANNUAL REPORT
OF

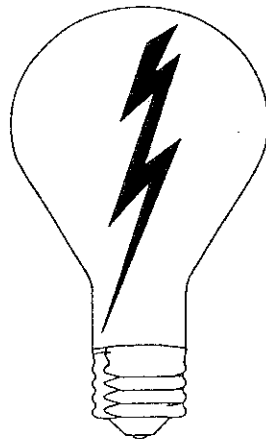
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PUBLIC SERVICE
COMMISSION

MONTANA-DAKOTA UTILITIES CO.

ELECTRIC UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

2009 Electric Annual Report

Instructions

General

1. A Microsoft EXCEL[®] workbook of the annual report is provided on our website for your convenience. The workbook contains the schedules of the annual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1". By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell. You may also obtain these instructions and the report in both an Adobe Acrobat[®] format and as an EXCEL[®] file from our website at <http://psc.mt.gov/>. Please be sure you use the 2009 report form.
2. Use of the EXCEL[®] workbook is optional.
3. All forms must be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report must be filed. **Please submit one unbound copy of the annual report along with the regular number of annual reports that you submit.** This aids in scanning the report so that it may be published on our web site. The orientation and margins are set up on each individual worksheet and should print on one page.
4. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ().
5. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.
6. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).
7. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.
8. All companies owned by another company shall attach a corporate structure chart of the holding company.
9. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

10. The following schedules shall be filled out with information on a total company basis:

Schedules 1 through 5
Schedules 6 and 7
Schedule 14
Schedule 17 and 18
Schedules 23 through 26
Schedules 33 and 34

11. All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

12. Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

13. FERC Form-I sheets may not be substituted in lieu of completing annual report schedule.

14. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 101 shall be used.
2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.
3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

Schedule 12

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was \$5,000 or more. Utilities having jurisdictional revenue equal to or in excess of \$1,000,000 shall report aggregate payments of \$25,000 or more. Utilities having jurisdictional revenue equal to or in excess of \$10,000,000 shall report aggregate payments of \$75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.
2. Companies with defined benefit plans must complete the entire form using FASB 87 and 132 guidelines.
3. Interest rate percentages shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 15 and 16. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 15 and 16. All assumptions used in quantifying cost containment results shall be disclosed.
2. Schedule 15 shall be filled out using FASB 106 and 132 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.
2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.
3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.
4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)
2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.
2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.
3. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 31

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of \$50,000 or more. Utilities having jurisdictional revenue equal to or in excess of \$1,000,000 shall itemize projects of \$100,000 or more. Utilities having jurisdictional revenue equal to or in excess of \$10,000,000 shall itemize projects of \$1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 32

1. Provide a written narrative detailing the sources and amounts of electric supply at the time of the annual peak.

Schedule 34

1. The following categories shall be used in the Type column: Thermal, Hydro, Nuclear, Solar, Wind, GeoThermal, Qualifying Facility (QF), Independent Power Producer (IPP), Off System Purchases, or Other. Spot market purchases shall be separately identified. Entries for the Other category shall be listed as separate line items and include a description.

Note: For Off System Purchases, the Utility/Company whom the purchases are being made from shall be entered in the Plant Name column, the termination date of the purchased power contract shall be entered in the Location column.

2. Provide a written narrative of all outages exceeding one hour which occurred during the year. Explain the reason for the outage. If routine maintenance schedules are exceeded, explain the reason.

Schedule 35

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.
2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

Schedule 35a

1. Contracted or committed current year expenditures include those expenditures that derive from preexisting contracts or commitments related to current year program activity but which will actually occur in a year other than the current year.
2. Expected average annual bill savings from weatherization should reflect average household bill savings based on the total households weatherized and the combined savings of all weatherization measures installed.

Electric Annual Report

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IDENTIFICATION

Year: 2009

1. Legal Name of Respondent:	MDU Resources Group, Inc.
2. Name Under Which Respondent Does Business:	Montana-Dakota Utilities Co.
3. Date Utility Service First Offered in Montana	1920
4. Address to send Correspondence Concerning Report:	Montana-Dakota Utilities Co. 400 North Fourth Street Bismarck, ND 58501
5. Person Responsible for This Report:	Rita A. Mulkern
5a. Telephone Number:	(701) 222-7854
Control Over Respondent	
1. If direct control over the respondent was held by another entity at the end of year provide the following:	
1a. Name and address of the controlling organization or person:	
1b. Means by which control was held:	
1c. Percent Ownership:	

SCHEDULE 2

Board of Directors ^{1/}		
Line No.	Name of Director and Address (City, State) (a)	Remuneration (b)
1	Terry D. Hildestad, Bismarck, ND	-
2	Vernon A. Raile, Bismarck, ND ^{2/}	-
3	Paul K. Sandness, Bismarck, ND	-
4	David L. Goodin, Bismarck, ND	-
5		-
6		-
7		
8	1/ Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc., and has no Board of Directors. The affairs of the Company are managed by a Managing Committee, the members of which are provided herein rather than the directors of MDU Resources Group, Inc.	
9		
10		
11		
12	2/ Vernon Raile retired from the Managing Committee effective February 2, 2010. Doran N. Schwartz was elected on February 3, 2010.	
13		
14		
15		
16		
17		
18		

Officers

Year: 2009

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President & Chief Executive Officer	Executive	David L. Goodin
2			
3			
4	Executive Vice President	Regulatory, Gas Supply and Business Development	Dennis L. Haider
5			
6			
7	Executive Vice President	Finance, Integration and Acquisitions	John F. Renner ^{1/}
8			
9	Executive Vice President	Utility Operations Support	Mike Gardner
10			
11	Vice President	Regulatory Affairs	Donald R. Ball ^{2/}
12			
13	Vice President	Electric Supply	Andrea L. Stomberg
14			
15	Vice President	Operations	Jay Skabo
16			
17	Vice President	Controller and Chief Accounting Officer	Garret Senger
18			
19			
20			
21	1/ John Renner retired on January 3, 2010.		
22	2/ Donald Ball retired on March 31, 2010.		
23			
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40			

CORPORATE STRUCTURE

Year: 2009

	Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
1	Montana-Dakota Utilities Co./	Electric and Natural Gas Distribution	\$54,895	21.08%
2	Great Plains Natural Gas Co.			
3	(Divisions of MDU Resources			
4	Group, Inc.) Cascade			
5	Natural Gas Corp. and			
6	Intermountain Gas Company			
7				
8	WBI Holdings, Inc. *	Pipeline and Energy Services and Natural Gas and Oil Production	125,515	48.19%
9				
10		Construction Materials and Mining	47,085	18.08%
11	Knife River Corp.			
12				
13		Construction Services	25,589	9.83%
14	MDU Construction Services			
15	Group, Inc.	Other	7,357	2.82%
16				
17	Centennial Energy Resources LLC/			
18	Centennial Holdings Capital Corp.			
19				
20				
21				
22				
23				
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36				
37				
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39				
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41				
42				
43				
44				
45				
46				
47				
48				
49				
50	TOTAL		\$260,441	100.00%

* Excludes the effect of a \$384.4 million after-tax noncash write-down of natural gas and oil properties.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 5

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2009

	Items Allocated	Classification	Allocation Method	\$ to MT Utility	MT %	\$ to Other
1	Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	\$2,521	1.33%	\$187,572
2						
3	Advertising	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	1,644	1.34%	121,366
4						
5	Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	807	1.16%	68,812
6						
7						
8	Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	500	2.29%	21,322
9						
10						
11	Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	4,528	1.32%	337,382
12						
13						
14	Computer Rental	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	121	1.74%	6,818
15						
16						
17	Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	22,042	2.30%	938,240
18						
19						
20	Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	42,564	1.93%	2,157,622
21						
22						
23	Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,645	1.28%	126,758
24						
25						
26	Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a Combination of Net Plant Investment and Number of Employees	26,932	1.40%	1,892,157
27						
28						
29						
30	Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on Number of Employees	2,085	1.39%	148,170
31						
32						

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2009

Items Allocated		Classification	Allocation Method	\$ to MT Utility	MT %	\$ to Other
1	Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	1,821	1.27%	141,859
2						
3	Employee Reimbursable Expenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,755	1.32%	131,639
4						
5						
6	Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	17,820	1.33%	1,320,033
7						
8						
9						
10	Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	39	1.39%	2,772
11						
12						
13	Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,272	1.26%	100,016
14						
15						
16	Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,817	1.28%	140,054
17						
18						
19	Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	1,357	1.59%	83,997
20						
21						
22	Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience	21,490	1.26%	1,682,218
23						
24						
25	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	608	1.73%	34,530
26						
27						
28	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	302	1.39%	21,465
29						
30						
31	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	334,790	1.53%	21,537,161
32						

Company Name: Montana-Dakota Utilities Co.

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2009

Items Allocated		Classification	Allocation Method	\$ to MT Utility	MT %	\$ to Other
1	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	280	1.73%	15,920
2						
3						
4	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	2,964	1.41%	207,914
5						
6						
7	Supplemental Insurance	Administrative & General	Various Corporate Overhead Allocation Factors	(12,594)	1.47%	(842,475)
8						
9	Seminars & Meeting Registrations	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,197	1.70%	69,283
10						
11						
12	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	8,877	1.84%	472,688
13						
14						
15	Telephone & Cell Phones	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3,593	1.57%	225,548
16						
17						
18	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	905	1.84%	48,281
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
31 TOTAL				\$493,682	1.55%	\$31,399,122

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	KNIFE RIVER CORPORATION	Expense	Actual Costs Incurred			
2		Contract Services		\$150		\$1,202
3		Materials		5,164		90
4		Office Expenses		385		16
5		Training		70		
6						
7		Capital	Actual Costs Incurred	17,094		4,243
8		Materials		1,022,182		253,676
9		Contract Services		2,035		474
10		Office Services				
11						
12		Other Transactions/Reimbursements	Actual Costs Incurred	1,372,681		
13		Balance Sheet Acct		681		
14		Non Utility		9,808		
15		Resource Cost Ctrs				
16						
17		Total Knife River Corporation Operating Revenues for the Year 2009			\$1,515,122,000	
18		Excludes Intersegment Eliminations				
19						
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$2,430,250	0.1604%	\$259,701

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	WBI HOLDINGS, INC.	Expense	Actual Costs Incurred			
2		Advertising		\$2,352		\$551
3		Contract Services		13,450		3,536
4		Fuel		34,191		9,939
5						
6		Capital	Actual Costs Incurred			
7		Material		191		48
8		Other		331		
9						
10		Other Transactions/Reimbursements	Actual Costs Incurred			
11		Auto Clearing		569		
12		Balance sheet accounts		2,446,354		
13		Non Utility		9,769		
14		Resource Cost Centers		22,953		
15						
16						
17						
18		Total WBI Holdings, Inc. Operating Revenues for the Year 2009			\$747,482,000	
19		Excludes Intersegment Eliminations				
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$2,530,160	0.3385%	\$14,074

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	MDU CONSTRUCTION SERVICES GROUP, INC	Expense	Actual Costs Incurred			
2		Office Expense		\$84		\$2
3		Materials		12,627		2,553
4		Capital				
5		Materials	Actual Costs Incurred	23,730		5,521
6		Office Expense		13		3
7		Other Transactions/Reimbursements				
8		Miscellaneous	Actual Costs Incurred	201,731		
9						
10						
11						
12						
13						
14					\$819,064,000	
15		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2009				
16		Excludes Intersegment Eliminations				
17						
18						
19						
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$238,185	0.0291%	\$8,079

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	CENTENNIAL HOLDINGS	Expense	* Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	\$129,190 21,249 141,373 219,387 4		\$30,285 4,665 33,142 51,430 1
2	CAPITAL, LLC	Contract Services				
3		Corporate Aircraft				
4		Office Expense				
5		Rent				
6		Other				
7			Actual Costs Incurred	238,610 3,608		55,519 478
8		Capital				
9		Contract Services				
10		Corporate Aircraft	Actual Costs Incurred	307,581 1,826,706 21,659 3,295		
11		Other Transactions/Reimbursements				
12		Resource Charges				
13		Balance Sheet Accounts				
14		Auto & Work				
15		Non Utility				
16					\$9,487,000	
17						
18						
19		Total Centennial Holdings Capital, LLC Operating Revenues for the Year 2009				
20		Grand Total Affiliate Transactions				
21						
22	TOTAL	Grand Total Affiliate Transactions		\$2,912,662	30.7016%	\$175,520

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	MDU ENERGY CAPITAL	Expense	Actual Costs Incurred	\$202,861		\$45,925
2		Payroll		1,770		351
3		Contract Services		19,081		4,473
4		Travel		86		17
5		Software Maintenance				
6		Other Transactions/Reimbursements	Actual Costs Incurred	1,977		
7		Miscellaneous				
8						
9						
10						
11		Total MDU Energy Capital Operating Revenues for the Year 2009			\$754,428,000	
12		Grand Total Affiliate Transactions				
13						
14						
15						
16						
17						
18						
19						
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$225,775	0.0299%	\$50,766

* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MDU RESOURCES GROUP, INC.	* Various Corporate Overhead Allocation Factors, Time Studies and/or Actual Costs Incurred			
2		Corporate Overhead				
3		Audit Costs		\$57,341		
4		Advertising		36,862		
5		Air Service		21,591		
6		Automobile		4,114		
7		Bank Services		103,265		
8		Corporate Aircraft		37,358		
9		Consultant Fees		314,254		
10		Contract Services		1,053,132		
11		Computer Rental		2,167		
12		Directors Expenses		550,053		
13		Employee Benefits		46,349		
14		Employee Meeting		45,064		
15		Employee Reimbursable Expense		42,884		
16		Express Mail		514		
17		Insurance		489,645		
18		Legal Retainers & Fees		402,136		
19		Meal Allowance		911		
20		Cash Donations		16,577		
21		Meals & Entertainment		30,080		
22		Industry Dues & Licenses		42,887		
23		Office Expenses		29,790		
24		Supplemental Insurance		(234,371)		
25		Permits & Filing Fees		10,749		
26		Postage		6,175		
27		Payroll		7,006,196		
28		Reference Materials		62,414		
29		Rental		3,464		
30		Seminars & Meeting Registrations		22,092		
31		Software Maintenance		190,714		
32		Telephone Expenses		103,918		
33		Training		16,509		
34						
35		Total MDU Resources Group, Inc.		\$10,514,834	0.7395%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MONTANA-DAKOTA UTILITIES CO.	Actual Costs Incurred			
2		Other Direct Charges		45,150		
3		Employee Discounts		1,541		
4		Dues, Permits, and Filing Fees		98,554		
5		Electric Consumption		122,191		74,346
6		Gas Consumption		80,567		
7		Miscellaneous		977,465		
8		Computer/Software Support				
9		Cost of Service		278,678		66,113
10						
11		Audit Costs		493,613		
12		Region Damage Billings		863		
13		Employee Reimbursable Exp		122,010		
14		Misc Employee Benefits		(16,412)		
15						
16						
17		Total Montana-Dakota Utilities Co.		2,204,220	0.1550%	140,459
18						
19						
20		OTHER TRANSACTIONS/REIMBURSEMENTS				
21						
22						
23		Federal & State Tax Liability Payments		43,012,117		
24		Tax Deferred Savings Plan		73,188		
25		Miscellaneous Reimbursements		(228,321)		
26						
27		Total Other Transactions/Reimbursements		42,856,984	3.0142%	
28						
29		Grand Total Affiliate Transactions		\$55,576,038	3.9087%	\$140,459
30						
31		Total Knife River Corporation Operating Expenses for 2009-Excludes Intersegment Eliminations			\$1,421,852,000	
32						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MDU RESOURCES GROUP, INC.	* Various Corporate Overhead Allocation Factors, Time Studies and/or Actual Costs Incurred			
2		Corporate Overhead				
3		Audit Costs		\$70,149		
4		Advertising		45,409		
5		Air Service		18,463		
6		Automobile		11,333		
7		Bank Services		126,164		
8		Corporate Aircraft		49,748		
9		Consultant Fees		280,234		
10		Contract Services		519,838		
11		Computer Rental		2,431		
12		Directors Expenses		709,988		
13		Employee Benefits		54,763		
14		Employee Meeting		52,900		
15		Employee Reimbursable Expense		42,313		
16		Express Mail		210		
17		Insurance		605,365		
18		Legal Retainers & Fees		493,786		
19		Meal Allowance		1,008		
20		Cash Donations		19,938		
21		Meals & Entertainment		37,534		
22		Moving Expense		3,750		
23		Industry Dues & Licenses		53,288		
24		Office Expenses		28,761		
25		Supplemental Insurance		(317,011)		
26		Permits & Filing Fees		12,465		
27		Postage		7,542		
28		Payroll		8,113,347		
29		Reference Materials		77,482		
30		Rental		7,813		
31		Seminars & Meeting Registrations		25,321		
32		Software Maintenance		147,458		
33		Telephone		75,781		
34		Training Material		16,533		
35		Total MDU Resources Group, Inc.		\$11,394,104	0.9895%	

Year: 2009

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department Expense	* Various Corporate Overhead Allocation Factors, Cost of Service Factors, Time Studies and /or Actual Costs	\$3,812		
3		Network Circuit Charges				
4						
5						
6		Region Operations Expense	* Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	4,036		
7		Automobile		25		
8		Contract Services		4		
9		Materials		37		
10		Office Telephone		9,322		
11		Payroll		32		
12		Photocopier		46		
13		Utilities		2,061		
14		General & Administrative Expenses				
15						
16						
17						
18		Clearing Accounts	* Various Corporate Overhead Time Studies and/or Actual Costs Incurred	242		
19		Office Telephone				
20						
21						
22		Other Direct Charges	Actual Costs Incurred			
23		Utility/Merchandise Discounts		153,243		
24		Audit Costs		325,581		
25		Radio Maintenance		1,095		
26		Vehicle Maintenance		14,571		
27		Dues, Permits, and Filing Fees		5,650		
28		Misc Employee Benefits		3,638		
29		Computer/Software Support		281,812		
30		Electric Consumption		1,288,089		
31		Gas Consumption		49,994		
32		Cost of Service		313,654		
33		Region Billings		5,849		
34		Legal Fees		11,184		
35		Employee Reimbursable Exp		36,250		
						947,568
						32,456
						74,411

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Telephone Expense	7,315 58,182 90,060	0.2315%	\$1,054,434
2		Miscellaneous			
3		BitterCreek Projects			
4		Total Montana-Dakota Utilities Co. 1/	\$2,665,784	-0.8370%	\$1,054,434
5		OTHER TRANSACTIONS/REIMBURSEMENTS	(9,562,040)		
6		Federal & State Tax Liability Payments	7,277		
7		Tax Deferred Savings Plan	(82,885)		
8		Miscellaneous Reimbursements	(9,637,648)		
9		Total Other Transactions/Reimbursements	\$4,422,240	0.3840%	
10		Grand Total Affiliate Transactions			
11		Total WBI Holdings Operating Expenses for 2009 - Excludes Intersegment Eliminations		\$1,151,493,000	
12					
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* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU CONSTRUCTION SERVICES GROUP INC	MDU RESOURCES GROUP, INC.	* Various Corporate Overhead Allocation Factors, Time Studies and/or Actual Costs Incurred			
2		Corporate Overhead				
3		Audit Costs		\$13,484		
4		Advertising		8,680		
5		Air Service		8,202		
6		Automobile		699		
7		Bank Services		24,277		
8		Corporate Aircraft		8,783		
9		Consultant Fees		42,043		
10		Contract Services		86,099		
11		Computer Rental		433		
12		Directors Expenses		130,723		
13		Employee Benefits		10,565		
14		Employee Meeting		10,514		
15		Employee Reimbursable Expense		11,070		
16		Express Mail		309		
17		Insurance		118,158		
18		Legal Retainers & Fees		94,632		
19		Meal Allowance		195		
20		Cash Donations		3,885		
21		Meals & Entertainment		7,182		
22		Industry Dues & Licenses		9,970		
23		Office Expenses		5,291		
24		Supplemental Insurance		(56,236)		
25		Permits & Filing Fees		2,455		
26		Postage		1,451		
27		Payroll		1,107,468		
28		Reference Materials		14,766		
29		Rent		822		
30		Seminars & Meeting Registrations		4,292		
31		Software Maintenance		23,765		
32		Telephone		7,098		
33		Training Material		3,042		
34				\$1,704,117	0.2199%	
35		Total MDU Resources Group, Inc.				

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU CONSTRUCTION SERVICES GROUP INC	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead	\$17		
3		Air Service	Allocation Factors, Cost of	6		
4		Automobile	Service Factors, Time Studies	1		
5		Meals & Entertainment	and/or Actual Costs Incurred	22,579		
6		Office Telephone		6,965		
7		Payroll		4		
8		Employee Reimbursable Expense		135		
9		Materials		22		
10		Industry Dues & Licenses				
11						
12		Other Miscellaneous Departments	* Various Corporate Overhead	56		
13		Payroll	Allocation Factors and/or Actual	(1)		
14		Other	Costs Incurred			
15						
16		Other Direct Charges	Actual Costs Incurred			
17		Legal Fees		989		
18		Audit		321,662		
19		Computer/Software Support		20,646		
20		Employee Reimbursable Expense		87		
21		Cost of Service		107,168		
22		Misc Employee Benefits		832,964		
23		Contract Services		2,981		
24		Dues, Permits, and Filing Fees		11,291		
25		Telephone Expense		9,941		
26		Miscellaneous		81,896		
27		Employee Discounts		6,508		
28		Gas Consumption		2,832		
29						
30						
31		Total Montana-Dakota Utilities Co.		\$1,428,749	0.1844%	\$25,425
						2,832
						\$28,257

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU CONSTRUCTION SERVICES GROUP INC	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Federal & State Tax Liability Payments		\$4,874,937		
3		Tax Deferred Savings Plan		7,644		
4		Miscellaneous Reimbursements		(143,982)		
5						
6		Total Other Transactions/Reimbursements		\$4,738,599	0.6116%	
7		Grand Total Affiliate Transactions		\$7,871,465	1.0159%	\$28,257
8						
9		Total MDU Construction Services Group, Inc. Operating Expenses for 2009			\$774,809,000	
10		Excludes Intersegment Eliminations				
11						
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* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL ENERGY RESOURCES	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead				
3		Insurance		\$213		
4		Payroll		338,200		
5		Total MDU Resources Group, Inc.		\$338,413	21.0194%	
6		MONTANA-DAKOTA UTILITIES CO.				
7		Other Miscellaneous Departments				
8		Payroll				
9				3,072		
10		Other Direct Charges				
11		Audit Costs				
12		Dues, Permits, and Filing Fees		33,600		
13		Miscellaneous Emp Benefits		626		
14		Employee Reimbursable Exp		7,339		
15		Miscellaneous		843		
16		Total Montana-Dakota Utilities Co.		3,696	3.0540%	
17				\$49,176		
18		OTHER TRANSACTIONS/REIMBURSEMENTS				
19		Federal & State Tax Liability Payments		(3,791,432)		
20		Miscellaneous Reimbursements		(200)		
21		Total Other Transactions/Reimbursements		(3,791,632)	-235.5051%	
22						
23		Grand Total Affiliate Transactions		(\$3,404,043)	-211.4312%	
24						
25		Total Centennial Energy Resources Operating Expenses for 2009				
26		Excludes Intersegment Eliminations				
27					\$1,610,000	

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* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL HOLDINGS	MONTANA-DAKOTA UTILITIES CO.				
2	CAPITAL CORP. AND					
3	FUTURESOURCE					
4		Other Direct Charges	Actual costs incurred	\$470		
5		Dues, Permits, and Filing Fees		46,933		
6		Computer/Software Support		15,445		
7		Employee Reimbursable Exp		3,315		
8		Legal Fees		137,807		
9		Electric Consumption		9,996		
10		Gas Consumption		451,539		
11		Payroll		60,644		
12		Miscellaneous		\$726,149	8.9692%	
13		Total Montana-Dakota Utilities Co.				
14		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
15		Insurance		21,137		
16		Miscellaneous Reimbursements		(2,033)		
17		Federal & State Tax Liability Payments		2,316,751		
18		Total Other Transactions/Reimbursements		\$2,335,855	28.8520%	
19						
20		Grand Total Affiliate Transactions		\$3,062,004	37.8212%	
21						
22		Total CHCC Operating Expenses for 2009			\$8,096,000	
23		Excludes Intersegment Eliminations				
24						
25						
26						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	MDU RESOURCES GROUP, INC.	* Various Corporate Overhead Allocation Factors, Time Studies and/or Actual Costs Incurred			
2	CAPITAL **	Corporate Overhead				
3		Audit Costs		\$30,368		
4		Advertising		19,827		
5		Air Service		15,359		
6		Automobile		1,696		
7		Bank Services		54,529		
8		Corporate Aircraft		19,738		
9		Consultant Fees		154,361		
10		Contract Services		230,459		
11		Computer Rental		1,005		
12		Directors Expenses		327,306		
13		Employee Benefits		26,754		
14		Employee Meeting		21,702		
15		Employee Reimbursable Expense		23,816		
16		Express Mail		60		
17		Insurance		330,066		
18		Legal Retainers & Fees		214,750		
19		Meal Allowance		406		
20		Cash Donations		8,448		
21		Meals & Entertainment		16,910		
22		Industry Dues & Licenses		17,613		
23		Office Expenses		11,416		
24		Supplemental Insurance		(153,533)		
25		Permits & Filing Fees		4,959		
26		Postage		3,260		
27		Payroll		2,809,124		
28		Reference Materials		34,132		
29		Rental		2,029		
30		Seminars & Meeting Registrations		9,865		
31		Software Maintenance		53,528		
32		Telephone		15,553		
33		Training Material		6,377		
34						
35		Total MDU Resources Group, Inc.		\$4,311,883	0.6184%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	CAPITAL **	Communications Department	* Various Corporate Overhead	\$53,554		
3		Payroll	Allocation Factors, Cost of	823		
4		Telephone	Service Factors, Time Studies			
5			and/or Actual Costs Incurred			
6		Customer Service/Call Center	* General Office Complex and	72,437		
7		Payroll	Office Supplies Cost of Service			
8			Allocation			
9		Information Systems	* Various Corporate Overhead	80,716		
10		Payroll	Allocation Factors, Cost of Service			
11			Factors, Time Studies and/or			
12			Actual Costs Incurred			
13		Other Miscellaneous Departments	* Various Corporate Overhead	8,803		
14		Payroll	Allocation Factors, Cost of Service	(779)		
15		Other	Factors, Time Studies and/or			
16			Actual Costs Incurred			
17		Payroll Accounting	* Various Corporate Overhead	84,835		
18		Payroll	Allocation Factors, Cost of Service	3441		
19		Other	Factors, Time Studies and/or			
20			Actual Costs Incurred			
21		Executive Departments	* Various Corporate Overhead	571,491		
22		Payroll	Allocation Factors, Cost of Service	7,555		
23		Employee Reimbursable Expense	Factors, Time Studies and/or	5,548		
24		Meals & Entertainment	Actual Costs Incurred	51,826		
25		Reference Materials				
26		Transportation Department	* Various Corporate Overhead	136,802		
27		Payroll	Allocation Factors, Cost of Service	2,525		
28		Employee Reimbursable Expense	Factors, Time Studies and/or	841		
29		Meals & Entertainment	Actual Costs Incurred			
30						
31						
32						
33						
34						
35						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	Automobile	Actual costs incurred	3,928	1.6805%	
2	CAPITAL **	Other		2,309		
3		OTHER TRANSACTIONS/REIMBURSEMENTS				
4		Other Direct Charges		1,519,256		
5		Misc Employee Benefits		511,699		
6		Audit Costs		727,945		
7		Cost of Service		612,513		
8		Computer/Software Support		30,329		
9		Legal Fees		4,492,216		
10		Contract Services		54,938		
11		Employee Reimbursable Exp		\$206,568		
12		Dues, Permits, and Filing Fees		17,231		
13		Telephone Expense		2,457,215		
14		Miscellaneous		\$11,716,565		
15		Total Montana-Dakota Utilities Co.				
16		Federal & State Tax Liability Payments		11,650,061		
17		Miscellaneous Reimbursements		(64,469)		
18		Total Other Transactions/Reimbursements		11,585,592		
19						
20		Grand Total Affiliate Transactions		\$27,614,040		
21						
22		Total MDU Energy Capital Operating Expenses for 2009			3.9607%	
23		Excludes Intersegment Eliminations			\$697,209,000	
24						
25						

* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital.

Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

** MDU Energy Capital is the parent company for Cascade Natural Gas Company and Intermountain Gas Company.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	HOLDING INC					
3		Other Direct Charges				
4		Audit Costs		\$98,600		
5		Employee Reimbursable Exp		2,774		
6		Miscellaneous		235,826		
7		Total Montana-Dakota Utilities Co.		\$337,200		
8						
9		Grand Total Affiliate Transactions		\$337,200		
10						
11						
12						
13						

MONTANA UTILITY INCOME STATEMENT

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	\$47,668,373	\$46,362,568	-2.74%
2				
3	Operating Expenses			
4	401 Operation Expenses	\$28,398,142	\$26,853,283	-5.44%
5	402 Maintenance Expense	3,964,001	3,627,112	-8.50%
6	403 Depreciation Expense	5,338,661	5,203,039	-2.54%
7	404-405 Amortization of Electric Plant	288,124	324,740	12.71%
8	406 Amort. of Plant Acquisition Adjustments	103,749	56,807	-45.25%
9	407 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Study Costs			
11	408.1 Taxes Other Than Income Taxes	3,184,308	3,079,492	-3.29%
12	409.1 Income Taxes - Federal	(943,895)	(1,298,447)	-37.56%
13	- Other	(110,721)	(158,094)	-42.79%
14	410.1 Provision for Deferred Income Taxes	1,984,787	2,532,811	27.61%
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	369,126	403,466	9.30%
16	411.4 Investment Tax Credit Adjustments			
17	411.6 (Less) Gains from Disposition of Utility Plant			
18	411.7 Losses from Disposition of Utility Plant			
19				
20	TOTAL Utility Operating Expenses	\$42,576,282	\$40,624,209	-4.58%
21	NET UTILITY OPERATING INCOME	\$5,092,091	\$5,738,359	12.69%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Electricity			
2	440 Residential	\$13,286,405	\$12,853,138	-3.26%
3	442 Commercial & Industrial - Small	8,005,129	7,811,028	-2.42%
4	Commercial & Industrial - Large	20,981,552	21,430,781	2.14%
5	444 Public Street & Highway Lighting	786,236	788,279	0.26%
6	445 Other Sales to Public Authorities	387,237	384,198	-0.78%
7	446 Sales to Railroads & Railways			
8	448 Interdepartmental Sales			
9	Net Unbilled Revenue	(216,190)	(222,132)	-2.75%
10	TOTAL Sales to Ultimate Consumers	\$43,230,369	\$43,045,292	-0.43%
11	447 Sales for Resale	2,443,467	1,325,685	-45.75%
12				
13	TOTAL Sales of Electricity	\$45,673,836	\$44,370,977	-2.85%
14	449.1 (Less) Provision for Rate Refunds			
15				
16	TOTAL Revenue Net of Provision for Refunds	\$45,673,836	\$44,370,977	-2.85%
17	Other Operating Revenues			
18	450 Forfeited Discounts & Late Payment Revenues			
19	451 Miscellaneous Service Revenues	\$18,648	\$15,949	-14.47%
20	453 Sales of Water & Water Power			
21	454 Rent From Electric Property	820,415	934,846	13.95%
22	455 Interdepartmental Rents			
23	456 Other Electric Revenues	1,155,474	1,040,796	-9.92%
24				
25	TOTAL Other Operating Revenues	\$1,994,537	\$1,991,591	-0.15%
26	Total Electric Operating Revenues	\$47,668,373	\$46,362,568	-2.74%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

Account Number & Title		Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	\$529,205	\$488,190	-7.75%
6	501 Fuel	12,849,201	11,289,890	-12.14%
7	502 Steam Expenses	970,116	938,286	-3.28%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	314,439	335,134	6.58%
11	506 Miscellaneous Steam Power Expenses	740,424	743,717	0.44%
12	507 Rents	78	166	112.82%
13				
14	TOTAL Operation - Steam	15,403,463	13,795,383	-10.44%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	207,036	198,427	-4.16%
18	511 Maintenance of Structures	141,740	156,209	10.21%
19	512 Maintenance of Boiler Plant	1,427,485	1,332,059	-6.68%
20	513 Maintenance of Electric Plant	257,245	243,249	-5.44%
21	514 Maintenance of Miscellaneous Steam Plant	274,382	267,866	-2.37%
22				
23	TOTAL Maintenance - Steam	2,307,888	2,197,810	-4.77%
24				
25	TOTAL Steam Power Production Expenses	\$17,711,351	\$15,993,193	-9.70%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	TOTAL Nuclear Power Production Expenses			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

Account Number & Title		Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	Hydraulic Power Generation			
3	Operation			
4	535 Operation Supervision & Engineering			
5	536 Water for Power			
6	537 Hydraulic Expenses			
7	538 Electric Expenses			
8	539 Miscellaneous Hydraulic Power Gen. Expenses			
9	540 Rents			
10				
11	TOTAL Operation - Hydraulic			
12				
13	Maintenance			
14	541 Maintenance Supervision & Engineering			
15	542 Maintenance of Structures			
16	543 Maint. of Reservoirs, Dams & Waterways			
17	544 Maintenance of Electric Plant			
18	545 Maintenance of Miscellaneous Hydro Plant			
19				
20	TOTAL Maintenance - Hydraulic			
21				
22	TOTAL Hydraulic Power Production Expenses			
23				
24	Other Power Generation			
25	Operation			
26	546 Operation Supervision & Engineering	\$37,195	\$29,474	-20.76%
27	547 Fuel	222,792	123,795	-44.43%
28	548 Generation Expenses	47,926	74,457	55.36%
29	549 Miscellaneous Other Power Gen. Expenses	67,640	62,996	-6.87%
30	550 Rents	939	13,116	1296.81%
31				
32	TOTAL Operation - Other	376,492	303,838	-19.30%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	21,122	14,971	-29.12%
36	552 Maintenance of Structures	1,264	1,837	45.33%
37	553 Maintenance of Generating & Electric Plant	44,551	50,784	13.99%
38	554 Maintenance of Misc. Other Power Gen. Plant	13	641	4830.77%
39				
40	TOTAL Maintenance - Other	66,950	68,233	1.92%
41				
42	TOTAL Other Power Production Expenses	\$443,442	\$372,071	-16.09%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	\$4,298,525	\$4,983,897	15.94%
46	556 System Control & Load Dispatching	288,342	277,272	-3.84%
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	\$4,586,867	\$5,261,169	14.70%
50				
51	TOTAL Power Production Expenses	\$22,741,660	\$21,626,433	-4.90%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

Account Number & Title		Last Year	This Year	% Change
1	Transmission Expenses			
2	Operation			
3	560 Operation Supervision & Engineering	\$381,949	\$338,929	-11.26%
4	561 Load Dispatching	354,509	339,119	-4.34%
5	562 Station Expenses	144,005	146,347	1.63%
6	563 Overhead Line Expenses	38,901	26,238	-32.55%
7	564 Underground Line Expenses			
8	565 Transmission of Electricity by Others	127,337	311,952	144.98%
9	566 Miscellaneous Transmission Expenses	36,357	33,247	-8.55%
10	567 Rents	170,442	174,752	2.53%
11	575 Day-Ahead and Real-Time Market Administration	106,046	122,669	15.68%
12				
13	TOTAL Operation - Transmission	1,359,546	1,493,253	9.83%
14	Maintenance			
15	568 Maintenance Supervision & Engineering	15,489	6,937	-55.21%
16	569 Maintenance of Structures			
17	570 Maintenance of Station Equipment	131,180	175,437	33.74%
18	571 Maintenance of Overhead Lines	218,293	105,458	-51.69%
19	572 Maintenance of Underground Lines			
20	573 Maintenance of Misc. Transmission Plant			
21				
22	TOTAL Maintenance - Transmission	364,962	287,832	-21.13%
23				
24	TOTAL Transmission Expenses	\$1,724,508	\$1,781,085	3.28%
25	Distribution Expenses			
26	Operation			
27	580 Operation Supervision & Engineering	\$292,877	\$196,518	-32.90%
28	581 Load Dispatching			
29	582 Station Expenses	121,316	80,862	-33.35%
30	583 Overhead Line Expenses	12,549	45,514	262.69%
31	584 Underground Line Expenses	158,233	130,250	-17.68%
32	585 Street Lighting & Signal System Expenses	4,164	21,297	411.46%
33	586 Meter Expenses	190,053	164,924	-13.22%
34	587 Customer Installations Expenses	118,571	92,150	-22.28%
35	588 Miscellaneous Distribution Expenses	500,230	520,644	4.08%
36	589 Rents	25,275	28,285	11.91%
37				
38				
39	TOTAL Operation - Distribution	1,423,268	1,280,444	-10.03%
40	Maintenance			
41	590 Maintenance Supervision & Engineering	136,163	81,692	-40.00%
42	591 Maintenance of Structures			
43	592 Maintenance of Station Equipment	37,653	16,449	-56.31%
44	593 Maintenance of Overhead Lines	549,563	545,262	-0.78%
45	594 Maintenance of Underground Lines	164,760	130,334	-20.89%
46	595 Maintenance of Line Transformers	48,620	26,430	-45.64%
47	596 Maintenance of Street Lighting, Signal Systems	52,366	44,853	-14.35%
48	597 Maintenance of Meters	18,752	17,144	-8.58%
49	598 Maintenance of Miscellaneous Dist. Plant	98,737	104,389	5.72%
50				
51	TOTAL Maintenance - Distribution	1,106,614	966,553	-12.66%
52				
53	TOTAL Distribution Expenses	\$2,529,882	\$2,246,997	-11.18%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

Account Number & Title		Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	\$102,250	\$55,403	-45.82%
4	902 Meter Reading Expenses	184,578	163,083	-11.65%
5	903 Customer Records & Collection Expenses	419,957	441,217	5.06%
6	904 Uncollectible Accounts Expenses	40,739	32,751	-19.61%
7	905 Miscellaneous Customer Accounts Expenses	74,661	75,002	0.46%
8				
9	TOTAL Customer Accounts Expenses	\$822,185	\$767,456	-6.66%
10	Customer Service & Information Expenses			
11				
12	Operation			
13	907 Supervision	\$10,970	\$15,862	44.59%
14	908 Customer Assistance Expenses	9,708	19,141	97.17%
15	909 Informational & Instructional Adv. Expenses	3,330	4,268	28.17%
16	910 Miscellaneous Customer Service & Info. Exp.	5	3	-40.00%
17				
18	TOTAL Customer Service & Info Expenses	\$24,013	\$39,274	63.55%
19	Sales Expenses			
20				
21	Operation			
22	911 Supervision	\$11,964	\$2,468	-79.37%
23	912 Demonstrating & Selling Expenses	33,319	25,905	-22.25%
24	913 Advertising Expenses	1,674	2,994	78.85%
25	916 Miscellaneous Sales Expenses	7,837	7,451	-4.93%
26				
27	TOTAL Sales Expenses	\$54,794	\$38,818	-29.16%
28	Administrative & General Expenses			
29				
30	Operation			
31	920 Administrative & General Salaries	\$1,160,831	\$1,170,630	0.84%
32	921 Office Supplies & Expenses	622,844	616,812	-0.97%
33	922 (Less) Administrative Expenses Transferred - Cr.			
34	923 Outside Services Employed	119,269	112,512	-5.67%
35	924 Property Insurance	107,989	144,571	33.88%
36	925 Injuries & Damages	136,083	184,724	35.74%
37	926 Employee Pensions & Benefits	1,954,171	1,354,912	-30.67%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	126,133	167,866	33.09%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	12,553	8,507	-32.23%
42	930.2 Miscellaneous General Expenses	35,226	55,223	56.77%
43	931 Rents	72,415	57,891	-20.06%
44				
45	TOTAL Operation - Admin. & General	4,347,514	3,873,648	-10.90%
46	Maintenance			
47	935 Maintenance of General Plant	117,587	106,684	-9.27%
48				
49	TOTAL Administrative & General Expenses	\$4,465,101	\$3,980,332	-10.86%
50				
51	TOTAL Operation & Maintenance Expenses	\$32,362,143	\$30,480,395	-5.81%

MONTANA TAXES OTHER THAN INCOME

Year: 2009

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	\$436,475	\$434,508	-0.45%
2	Secretary of State	270	223	-17.41%
3	Highway Use Tax	503	479	-4.77%
4	Montana Consumer Counsel	54,490	29,321	-46.19%
5	Montana PSC	129,332	107,136	-17.16%
6	Montana Electric	53,913	53,066	-1.57%
7	Coal Conversion	284,381	274,305	-3.54%
8	Delaware Franchise	21,692	24,104	11.12%
9	Property Taxes	2,203,252	2,156,350	-2.13%
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50	TOTAL MT Taxes Other Than Income	\$3,184,308	\$3,079,492	-3.29%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 2009

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Able Field Services	Plant Update & Repair	\$91,948	\$22,823	24.82%
2					
3	Aerial Contractors Inc.	Contractor Services	178,847	0	0.00%
4					
5	Agri Industries Inc.	Contractor Services	124,786	30,997	24.84%
6					
7	Aptech CST, LLC	Engineering Services - L&C	240,435	59,681	24.82%
8					
9	Barr Engineering Co.	Engineering Services - Heskett	90,380	22,434	24.82%
10					
11	Benco Equipment Co.	Vehicle Maintenance	233,213	13,278	5.69%
12					
13	BHCI	Contractor Services	104,205	0	0.00%
14					
15	Big K Industries, Inc.	Contractor Services	227,515	56,073	24.65%
16					
17	Blue Heron Consulting	Consulting Services	1,489,302	128,360	8.62%
18					
19	Broadridge	Shareholder Position Process	156,970	1,950	1.24%
20					
21	Bullinger Tree Service	Tree Trimming Service	370,175	9,064	2.45%
22					
23	Central Trenching Inc.	Boring & Trenching Services	121,356	0	0.00%
24					
25	Chief Construction	Contractor Services	679,637	0	0.00%
26					
27	Cisco Systems Capital Corp.	Software Maintenance	121,222	2,316	1.91%
28					
29	Connecting Point	Computer Svcs & Software Maint.	134,166	10,368	7.73%
30					
31	Dell Marketing, LP	Software Maintenance	103,247	3,310	3.21%
32					
33	Deloitte & Touche LLP	Auditing & Consulting Services	351,701	21,988	6.25%
34					
35	Dewey & LeBoeuf	Legal Services	741,445	9,830	1.33%
36					
37	Edison Electric Institute	Membership Dues	65,857	13,850	21.03%
38					
39	Edling Electric Inc.	Fiber Optic Installation	173,325	0	0.00%
40					
41	Fischer Contracting	Contract Services	304,454	0	0.00%
42					
43	Gary Forrester	Contract Services	90,885	1,206	1.33%
44					
45	Franz Construction Inc.	Construction Services	146,891	36,461	24.82%
46					
47	G E Energy Services	Construction Services	463,706	114,554	24.70%
48					
49	Gagnon, Inc.	Contractor Services	75,075	18,635	24.82%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 2009

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	GE Energy Management Services	Testing at Power Plants	\$146,548	\$36,376	24.82%
2					
3	GLS Companies	Contract Service - Annual Report	125,446	1,559	1.24%
4					
5	Hewlett-Packard Co.	Consulting Services	89,610	7,723	8.62%
6					
7	Highmark, Inc.	Construction Services	339,100	84,171	24.82%
8					
9	Hughes, Keller, Sullivan & Alke, PLLP	Legal Services	88,936	23,986	26.97%
10					
11	Hydrochem Industrial Services	Boiler Cleaning	256,869	63,760	24.82%
12					
13	Impact Mechanical Inc.	Carbon Injection Sys - L&C	613,125	152,190	24.82%
14					
15	Industrial Contractors Inc.	Construction Services	604,953	150,241	24.84%
16					
17	Infrasource	Underground Gas Line Installment	1,323,875	0	0.00%
18					
19	International Business Machines Inc.	Contractor Serv - Computer Maint.	150,757	13,682	9.08%
20					
21	Itron Inc.	Contract Services	287,835	21,208	7.37%
22					
23	M C M General Contractors, Inc.	Boring & Pipe Installation	262,096	0	0.00%
24					
25	Martin Construction Inc.	Ash Disposal - Heskett	522,447	128,665	24.63%
26					
27	Marting Engineering	Dust Control L&C Station	125,000	31,027	24.82%
28					
29	McDermott, Will & Emery, LLP	Legal Services	143,402	1,872	1.31%
30					
31	Microbeam Technologies Inc.	Contr Serv - Limestone Testing	140,019	34,755	24.82%
32					
33	Microsoft	Software Maintenance	131,893	12,892	9.77%
34					
35	Midwest ISO	Prelim Studies, Cedar Hills	125,000	30,849	24.68%
36					
37	Midwest Testing Laboratory	Test Serv - Cedar Hills	89,449	22,203	24.82%
38					
39	Minnesota Valley Testing	Testing Services	104,860	27,725	26.44%
40					
41	Moorhead Boiler & Machinery Co.	Contract Services	81,814	20,308	24.82%
42					
43	Morgan, Lewis & Bockius LLP	Legal Services	364,911	5,160	1.41%
44					
45	New York Life	Consulting Services	394,249	15,628	3.96%
46					
47	NYSE Market Inc.	Financial Services	190,707	2,253	1.18%
48					
49	One Call Locators Ltd. (ELM)	Line Location Services	1,084,581	5,708	0.53%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 2009

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Oracle Corp.	Software Maintenance	\$539,635	\$47,628	8.83%
2					
3	Ormat Nevada Inc.	Install Energy Convertor - Glen Ullin	7,120,538	1,767,459	24.82%
4					
5	Otis Elevator Co.	Elevator Service - Office & Heskett	65,145	10,342	15.88%
6					
7	OTP Big Stone II - Trust Acct	Big Stone II Const	1,135,068	281,746	24.82%
8					
9	Presort Plus Inc.	Mail Services	117,426	13,301	11.33%
10					
11	Progressive Maintenance Co.	Custodial Services	131,331	20,041	15.26%
12					
13	Prosource Technologies Inc.	Pipeline Construction	237,095	0	0.00%
14					
15	PSC Industrial Outsourcing Inc.	Boiler Maintenance	619,202	155,713	25.15%
16					
17	Quality Underground Service Inc.	Gas Lines & Maintenance	168,714	0	0.00%
18					
19	Salo, Bertha	Contr Serv - CIS Project	76,525	6,563	8.58%
20					
21	Sargent & Lundy, LLC	Consulting Services	455,089	112,962	24.82%
22					
23	Standard & Poors	Financial Services	110,487	3,674	3.33%
24					
25	Toyo Tires	Vehicle Maintenance	96,396	0	0.00%
26					
27	Treasury Management Service	Banking Services	342,788	24,053	7.02%
28					
29	Ulmer Tree Service	Tree Trimming Service	126,364	0	0.00%
30					
31	Utilities International Inc.	Consulting Services	389,888	12,195	3.13%
32					
33	Ventyx Energy, LLC	Software Maintenance	81,885	19,741	24.11%
34					
35	Vic's Crane & Heavy Haul Service	Contr Services - Tioga Transformer	110,683	27,474	24.82%
36					
37	Wanzek Construction Inc.	Contractor Services	3,599,814	893,545	24.82%
38					
39	Wells Fargo Shareholders Services	Stock transfer agent & ESOP Admin.	307,911	4,036	1.31%
40					
41	Wenck	Contr Serv - Billings Landfill	288,200	0	0.00%
42					
43	Willis of Minnesota	Consulting Services	96,916	1,031	1.06%
44					
45	Workforce Services, Inc.	Vehicle Maintenance	106,694	0	0.00%
46					
47	Xerox Corp	Copier Maintenance	138,268	18,645	13.48%
48					
49	Yellowstone Electric Co.	Contract Services - Glendive Unit 2	\$89,100	\$22,116	24.82%
50					
51	TOTAL Payments for Services		31,219,387	4,913,384	15.74%

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

Year: 2009

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	\$15,784	\$660	4.18%
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43	TOTAL Contributions	\$15,784	\$660	4.18%

Pension Costs

Year: 2009

1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Traditional unit credit	IRS Code: 1A		
4	Annual Contribution by Employer: 8,347,434	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	Change in Benefit Obligation	(000's)	(000's)	
7	Benefit obligation at beginning of year	\$213,539	\$215,629	-0.97%
8	Service cost	5,036	5,349	-5.85%
9	Interest cost	13,169	12,767	3.15%
10	Plan participants' contributions	-	-	
11	Amendments	-	-	
12	Actuarial (Gain) Loss	17,651	(4,940)	457.31%
13	Curtailment gain	(24,085)	-	
14	Benefits paid	(15,689)	(15,266)	-2.77%
15	Benefit obligation at end of year	\$209,621	\$213,539	-1.83%
16	Change in Plan Assets			
17	Fair value of plan assets at beginning of year	\$134,645	\$201,282	-33.11%
18	Actual return on plan assets	24,853	(51,743)	148.03%
19	Interplan transfer (1)	270	372	-27.42%
20	Employer contribution	8,347	-	
21	Plan participants' contributions	-	-	
22	Benefits paid	(15,689)	(15,266)	-2.77%
23	Fair value of plan assets at end of year	\$152,426	\$134,645	13.21%
24	Funded Status	(57,195)	(78,894)	27.50%
25	Unrecognized net actuarial loss	-	-	
26	Unrecognized prior service cost	-	-	
27	Unrecognized net transition obligation	-	-	
28	Accrued benefit cost	(57,195)	(78,894)	27.50%
29				
30	Weighted-Average Assumptions as of Year End			
31	Discount rate	5.75	6.25	-8.00%
32	Expected return on plan assets	8.25	8.50	-2.94%
33	Rate of compensation increase	4.00	4.00	0.00%
34				
35	Components of Net Periodic Benefit Costs			
36	Service cost	\$5,036	\$5,349	-5.85%
37	Interest cost	13,169	12,767	3.15%
38	Expected return on plan assets	(15,429)	(15,973)	3.41%
39	Amortization of prior service cost	604	659	-8.35%
40	Recognized net actuarial gain	236	23	926.09%
41	Curtailment loss	1,143	-	
42	Net periodic benefit cost	\$4,759	\$2,825	68.46%
43				
44	Montana Intrastate Costs:			
45	Pension costs	\$4,759	\$2,825	68.46%
46	Pension costs capitalized	656	415	58.07%
47	Accumulated pension asset (liability) at year end	(57,195)	(78,894)	27.50%
48	Number of Company Employees:			
49	Covered by the plan	1,883	1,917	-1.77%
50	Not covered by the plan	252	248	1.61%
51	Active	889	937	-5.12%
52	Retired	931	923	0.87%
53	Deferred vested terminated	63	57	10.53%

(1) The company transferred assets between plans for employees that moved to a different MDU Resources Group, Inc. sponsored plan.

Other Post Employment Benefits (OPEBS)

Year: 2009

	Item	Current Year	Last Year	% Change
1	Regulatory Treatment:			
2	Commission authorized - most recent			
3	Docket number:			
4	Order numbers:			
5	Amount recovered through rates -			
6	Weighted-Average Assumptions as of Year End			
7	Discount rate	5.75	6.25	-8.00%
8	Expected return on plan assets	7.25	7.50	-3.33%
9	Medical cost inflation rate	6.00	6.00	0.00%
10	Actuarial cost method	Projected unit credit	Projected unit credit	
11	Rate of compensation increase	N/A	N/A	
12	List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:			
13	VEBA			
14	Describe any Changes to the Benefit Plan:			
15				
16				
	TOTAL COMPANY			
17	Change in Benefit Obligation	(000's)	(000's)	
18	Benefit obligation at beginning of year	\$50,698	\$48,565	4.39%
19	Service cost	1,106	1,172	-5.63%
20	Interest cost	2,838	2,956	-3.99%
21	Plan participants' contributions	1,526	1,384	10.26%
22	Amendments	(5,439)	-	
23	Actuarial (Gain) Loss	(1,618)	848	-290.80%
24	Acquisition	-	-	
25	Benefits paid	(4,263)	(4,227)	-0.85%
26	Benefit obligation at end of year	\$44,848	\$50,698	-11.54%
27	Change in Plan Assets			
28	Fair value of plan assets at beginning of year	\$35,466	\$47,494	-25.33%
29	Actual return on plan assets	3,411	(11,253)	130.31%
30	Acquisition	-	-	
31	Employer contribution	1,833	2,068	-11.36%
32	Plan participants' contributions	1,526	1,384	10.26%
33	Benefits paid	(4,263)	(4,227)	-0.85%
34	Fair value of plan assets at end of year	\$37,973	\$35,466	7.07%
35	Funded Status	(\$6,875)	(\$15,232)	54.86%
36	Unrecognized net actuarial loss	-	-	
37	Unrecognized prior service cost	-	-	
38	Unrecognized transition obligation	-	-	
39	Accrued benefit cost	(\$6,875)	(\$15,232)	54.86%
40	Components of Net Periodic Benefit Costs			
41	Service cost	\$1,106	\$1,172	-5.63%
42	Interest cost	2,838	2,956	-3.99%
43	Expected return on plan assets	(3,565)	(3,692)	3.44%
44	Amortization of prior service cost	36	36	0.00%
45	Recognized net actuarial gain	(198)	(116)	-70.69%
46	Transition amount amortization	1,678	1,694	-0.94%
47	Net periodic benefit cost	\$1,895	\$2,050	-7.56%
48	Accumulated Post Retirement Benefit Obligation			
49	Amount funded through VEBA	3,359	\$3,452	-2.69%
50	Amount funded through 401(h)			
51	Amount funded through Other _____			
52	TOTAL	\$3,359	\$3,452	-2.69%
53	Amount that was tax deductible - VEBA	1,833 (1)	2,068	-11.36%
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other _____			
56	TOTAL	\$1,833	\$2,068	-11.36%

Other Post Employment Benefits (OPEBS) Continued

Year: 2009

	Item	Current Year	Last Year	% Change
1	Number of Company Employees:			
2	Covered by the plan	1,783	1,822	-2.14%
3	Not covered by the plan	37	36	2.78%
4	Active	1,029	1,034	-0.48%
5	Retired	607	605	0.33%
6	Spouses/dependants covered by the plan	142	183	-22.40%
7	Montana			
8	Change in Benefit Obligation			
9	Benefit obligation at beginning of year	NOT APPLICABLE		
10	Service cost			
11	Interest cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	Change in Plan Assets			
19	Fair value of plan assets at beginning of year	NOT APPLICABLE		
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	Funded Status			
27	Unrecognized net actuarial loss	NOT APPLICABLE		
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	Components of Net Periodic Benefit Costs			
31	Service cost	NOT APPLICABLE		
32	Interest cost			
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	Accumulated Post Retirement Benefit Obligation			
38	Amount funded through VEBA	NOT APPLICABLE		
39	Amount funded through 401(h)			
40	Amount funded through other _____			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	Montana Intrastate Costs:			
47	Pension costs	NOT APPLICABLE		
48	Pension costs capitalized			
49	Accumulated pension asset (liability) at year end			
50	Number of Montana Employees:			
51	Covered by the plan	NOT APPLICABLE		
52	Not covered by the plan			
53	Active			
54	Retired			
55	Spouses/dependants covered by the plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							

PROPRIETARY SCHEDULE

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION 1/

Line No.	Name/Title	Base Salary	Bonuses	Other 2/	Total Compensation	Total Compensation Last Year 2/	% Increase Total Compensation
1	Terry D. Hildestad - President & CEO	\$750,000	\$1,500,000	\$1,953,004	\$4,203,004	\$3,119,702	35%
2	William Schneider - President & CEO of Knife River Corporation	447,400	581,620	1,136,063	2,165,083	1,097,551	97%
3	Vernon A. Raile Executive Vice President, Treasurer and CFO	450,000	585,000	1,105,718	2,140,718	1,432,401	49%
4	John G. Harp - President & CEO of MDU Construction Services Group	450,000	392,500	1,187,359	2,029,859	1,893,579	7%
5	Steven L. Bietz President & CEO of WBI Holdings, Inc.	350,000	450,450	797,056	1,597,506	635,279	151%

1/ See Page 19a for Total Compensation detail.

2/ Amounts represent the aggregate grant date fair value of the performance share awards calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718 - Share Based Payment.

Proxy Statement

Policy Regarding Hedging Stock Ownership

In our Executive Compensation Policy, we adopted a policy that prohibits executives from hedging their ownership of company common stock. Executives may not enter into transactions that allow the executive to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership.

Compensation Committee Report

The compensation committee has reviewed and discussed the Compensation Discussion and Analysis required by Reg. S-K, Item 402(b), with management. Based on the review and discussions referred to in the preceding sentence, the compensation committee recommended to the board of directors that the Compensation Discussion and Analysis be included in our proxy statement on Schedule 14A.

Thomas Everist, Chairman

Karen B. Fagg

Thomas C. Knudson

Patricia L. Moss

Summary Compensation Table for 2009

Name and Principal Position (a)	Year (b)	Salary (\$) (c)	Bonus (\$) (d)	Stock Awards (\$) (e)(1)	Option Awards (\$) (f)	Non-Equity Incentive Plan Compensation (\$) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (\$) (h)(2)	All Other Compensation (\$) (i)	Total (\$) (j)
Terry D. Hildestad President and CEO	2009	750,000	—	1,117,861	—	1,500,000	825,319	9,824 (3)	4,203,004
	2008	700,000	—	1,200,485	—	310,800	898,941	9,476	3,119,702
	2007	625,000	—	779,293	—	1,250,000	1,362,413	7,026	4,023,732
Vernon A. Raile Executive Vice President, Treasurer and CFO	2009	450,000	—	402,417	—	585,000	695,177	8,124 (3)	2,140,718
	2008	400,000	—	411,575	—	115,440	498,210	7,176	1,432,401
	2007	350,700	—	295,882	—	350,700	555,248	7,026	1,559,556
John G. Harp President and CEO of MDU Construction Services Group, Inc.	2009	450,000	—	402,417	—	392,500 (4)	761,670 (6)	23,272 (7)	2,029,859
	2008	400,000	—	411,575	—	720,000 (5)	338,774 (6)	23,230 (7)	1,893,579
	2007	341,000	—	239,763	—	341,000	47,334 (6)	23,080 (7)	992,177
William E. Schneider President and CEO of Knife River Corporation	2009	447,400	—	400,093	—	581,620	726,646	9,324 (3)	2,165,083
	2008	447,400	—	460,374	—	—	180,801	8,976	1,097,551
	2007	422,000	—	356,052	—	206,780	450,347	7,026	1,442,205
Steven L. Bietz President and CEO of WBI Holdings, Inc.	2009	350,000	—	312,987	—	450,450	475,985	8,084 (3)	1,597,506
	2008	—	—	—	—	—	—	—	—
	2007	—	—	—	—	—	—	—	—

(1) Amounts in this column represent the aggregate grant date fair value of the performance share awards calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718 – Share-Based Payment. Amounts for 2008 and 2007 have been recalculated to comply with the new requirements. This column was prepared assuming none of the awards will be forfeited. The amounts were calculated using a Monte Carlo simulation, as described in Note 13 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2009.

(2) Amounts shown represent the change in the actuarial present value for years ended December 31, 2007, 2008, and 2009 for the named executive officers' accumulated benefits under the pension plan, excess SISP, and SISP and, for Mr. Harp, the additional retirement benefit, collectively referred to as the "accumulated pension change," plus above market earnings on deferred annual incentives, if any. The amounts shown are based on accumulated pension change and above market earnings as of December 31, 2007, 2008, and 2009, as follows:

Name	Accumulated Pension Change			Above Market Earnings		
	12/31/2007 (\$)	12/31/2008 (\$)	12/31/2009 (\$)	12/31/2007 (\$)	12/31/2008 (\$)	12/31/2009 (\$)
Terry D. Hildestad	1,336,815	883,351	806,554	25,598	15,590	18,765
Vernon A. Raile	508,987	469,755	661,243	46,261	28,455	33,934
John G. Harp	38,498	331,558	743,334	-	-	-
Additional Retirement (John G. Harp)*	8,836	7,216	18,336	-	-	-
William E. Schneider	411,123	155,816	696,572	39,224	24,985	30,074
Steven L. Bietz	-	-	475,985	-	-	-

* See footnote 6.

(3) Includes company contributions to the 401(k), payment of a life insurance premium, and matching contributions to charitable organizations.

(4) Includes one-time incentive payment of \$100,000 in addition to his annual incentive compensation.

(5) Includes one-time incentive payment of \$200,000 in addition to his executive incentive compensation plan payment.

(6) In addition to the change in the actuarial present value of Mr. Harp's accumulated benefit under the pension plan, excess SISP, and SISP, this amount also includes the following amounts attributable to Mr. Harp's additional retirement benefit:

	2007	2008	2009
Change in present value of additional years of service for pension plan	\$6,033	\$3,570	\$13,077
Change in present value of additional years of service for excess SISP	2,803	3,646	5,259
Change in present value of additional years of service for SISP	-	-	-

Mr. Harp's additional retirement benefit is described in the narrative that follows the Pension Benefits for 2009 table. The additional retirement benefit provides Mr. Harp with additional retirement benefits equal to the additional benefit he would earn under the pension plan, excess SISP, and the SISP if he had three additional years of service. The amounts in the table above reflect the change in present value of this additional benefit in 2007, 2008, and 2009. The additional retirement benefit was determined by calculating the actuarial present values of the accumulated benefits under the pension plan, excess SISP, and SISP, with and without the three additional years of service, using the same assumptions used to determine the amounts disclosed in the Pension Benefits for 2009 table. Because Mr. Harp would be fully vested in his SISP benefit if he retired at age 65, the assumed retirement age of these calculations, the additional years of service provided by the additional retirement agreement would not increase that benefit. If Mr. Harp retires before becoming 100% vested in his SISP benefit, his SISP benefit would be less than the amount shown in the Pension Benefits for 2009 table, but the payments he would receive under the additional retirement benefit arrangement would increase, as would the amounts reflected in the table above and in the Summary Compensation Table.

(7) Includes a company contribution to Mr. Harp's 401(k), a matching contribution to a charity, payment of a life insurance premium, an additional premium for Mr. Harp's long-term disability insurance, and Mr. Harp's office and automobile allowance.

Grants of Plan-Based Awards in 2009

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Awards: Number of Shares of Stock or Units	All Other Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards (\$/Sh)	Grant Date Fair Value of Stock and Option Awards (\$)
		Threshold (\$) (c)	Target (\$) (d)	Maximum (\$) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	(i)	(j)	(k)	(l)
Terry D. Hildestad	2/12/09(1)	187,500	750,000	1,500,000	-	-	-	-	-	-	-
	2/12/09(2)	-	-	-	5,482	54,824	109,648	-	-	-	1,117,861
Vernon A. Raile	2/12/09(1)	73,125	292,500	585,000	-	-	-	-	-	-	-
	2/12/09(2)	-	-	-	1,973	19,736	39,472	-	-	-	402,417
John G. Harp	2/12/09(1)	73,125	292,500	585,000	-	-	-	-	-	-	-
	2/12/09(2)	-	-	-	1,973	19,736	39,472	-	-	-	402,417
William E. Schneider	2/12/09(3)	100,000	200,000	-	-	-	-	-	-	-	-
	2/12/09(1)	72,703	290,810	581,620	-	-	-	-	-	-	-
Steven L. Bietz	2/12/09(2)	-	-	-	1,962	19,622	39,244	-	-	-	400,093
	2/12/09(4)	56,875	227,500	455,000	-	-	-	-	-	-	-
	2/12/09(2)	-	-	-	1,535	15,350	30,700	-	-	-	312,987

(1) Annual incentive for 2009 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

(2) Performance shares for the 2009-2011 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

(3) Mr. Harp's additional 2009 incentive opportunity.

(4) Annual incentive for 2009 granted pursuant to the WBI Holdings Inc. Executive Incentive Compensation Plan.

Proxy Statement

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Incentive Awards

Annual Incentive

On February 11, 2009, the compensation committee recommended the 2009 annual incentive award opportunities for our named executive officers, and the board approved these opportunities at its meeting on February 12, 2009. These award opportunities are reflected in the Grants of Plan-Based Awards table at grant on February 12, 2009 in columns (c), (d), and (e) and in the Summary Compensation Table as earned with respect to 2009 in column (g).

Executive officers may receive annual cash incentive awards based upon achievement of annual performance measures with a threshold, target, and maximum level. A target incentive award is established based on a percent of the executive's base salary. Actual payment may range from zero to 200% of the target based upon achievement of corporate goals.

In order to be eligible to receive an annual incentive award under the Long-Term Performance-Based Incentive Plan, Messrs. Hildestad, Raile, Schneider, and Harp must have remained employed by the company through December 31, 2009, unless the compensation committee determines otherwise. The committee has full discretion to determine the extent to which goals have been achieved, the payment level, whether any final payment will be made, and whether to adjust awards downward based upon individual performance. Unless the committee determines otherwise, performance measure targets shall be adjusted to take into account unusual or nonrecurring events affecting the company, a subsidiary or a division or business unit, or any of their financial statements, or changes in applicable laws, regulations or accounting principles to the extent such unusual or nonrecurring events or changes in applicable laws, regulations or accounting principles otherwise would result in dilution or enlargement of the annual incentive award intended to be provided. Such adjustments are made in a manner that will not cause the award to fail to qualify as performance-based compensation for purposes of Section 162(m) of the Internal Revenue Code.

With respect to annual incentive awards granted pursuant to the WBI Holdings, Inc. Executive Incentive Compensation Plan, which includes Mr. Bietz, participants who retire at age 65 during the year remain eligible to receive an award. Subject to the compensation committee's discretion, executives who terminate employment for other reasons are not eligible for an award.

The committee has full discretion to determine the extent to which goals have been achieved, the payment level, and whether any final payment will be made. Once performance goals are approved by the committee for executive incentive compensation plan awards, the committee generally does not modify the goals. However, if major unforeseen changes in economic and environmental conditions or other significant factors beyond the control of management substantially affected management's ability to achieve the specified performance goals, the committee, in consultation with the chief executive officer, may modify the performance goals. Such goal modifications will only be considered in years of unusually adverse or favorable external conditions.

For Messrs. Hildestad and Raile, the performance measures for annual incentive awards are our annual return on invested capital achieved compared to target and our annual earnings per share achieved compared to target. For Messrs. Schneider, Harp, and Bietz, the performance measures for annual incentive awards are their respective business unit's annual return on invested capital achieved compared to target and their respective business unit's allocated earnings per share achieved compared to target. In 2009, Mr. Bietz had five individual goals relating to WBI Holdings Inc.'s safety results, and each goal that was not met reduced his annual incentive award by 1%.

For 2009, the compensation committee weighted the goals for annual return on invested capital compared to target and allocated earnings per share compared to target each at 50%.

We limit the after-tax annual incentive compensation we will pay above the target amount to 20% of earnings in excess of planned earnings. We calculate the earnings in excess of planned earnings without regard to the after-tax annual incentive amounts above target. We measure the 20% limitation at the major business unit level for business unit and operating company executives, which include Messrs. Harp, Schneider, and Bietz, and at the corporate level for corporate executives, which include Messrs. Hildestad and Raile. In 2009, the 20% limitation was calculated without regard to the noncash ceiling test impairment charge and an associated depletion, depreciation and amortization benefit as discussed in the Compensation Discussion and Analysis.

The award opportunities available to each named executive officer were:

2009 earnings per share results as a % of 2009 target	Corresponding payment of annual incentive target based on earnings per share
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

2009 return on invested capital results as a % of 2009 target	Corresponding payment of annual incentive target based on return on invested capital
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

For discussion of the specific incentive plan performance targets and results, please see the Compensation Discussion and Analysis.

In addition to his 2009 annual incentive award opportunity under our Long-Term Performance-Based Incentive Plan, Mr. Harp had an opportunity to earn an additional incentive, which was structured as follows:

MDU Construction Services Group, Inc.'s 2009 Return on Invested Capital (ROIC) as compared to MDU Construction Services Group, Inc.'s 2009 Weighted Average Cost of Capital (WACC)	Additional Incentive Amount
2009 ROIC is less than 100 basis points above 2009 WACC	\$0
2009 ROIC is 100 to 199 basis points above 2009 WACC	\$100,000
2009 ROIC is 200 basis points or more above 2009 WACC	\$200,000

For a specific discussion of this additional incentive opportunity and the compensation committee's determination with respect to payment, please refer to the Compensation Discussion and Analysis.

Long-Term Incentive

On February 11, 2009, the compensation committee recommended long-term incentive grants to the named executive officers in the form of performance shares, and the board approved these grants at its meeting on February 12, 2009. These grants are reflected in columns (f), (g), (h), and (i) of the Grants of Plan-Based Awards table and in column (e) of the Summary Compensation Table.

From 0% to 200% of the target grant will be paid out in February 2012, depending on our 2009-2011 total stockholder return compared to the total three-year stockholder returns of companies in our performance graph peer group. The payout percentage is determined as follows:

The Company's Percentile Rank	Payout Percentage of February 12, 2009 Grant
100th	200%
75th	150%
50th	100%
40th	10%
Less than 40th	0%

Payouts for percentile ranks falling between the intervals will be interpolated. We also will pay dividend equivalents in cash on the number of shares actually earned for the performance period. The dividend equivalents will be paid in 2012 at the same time as the performance awards are paid.

Proxy Statement

Salary and Bonus in Proportion to Total Compensation

The following table shows the proportion of salary to total compensation. We paid no bonuses to our named executive officers in 2009.

Name	Salary (\$)	Total Compensation (\$)	Salary as % of Total Compensation
Terry D. Hildestad	750,000	4,203,004	17.8
Vernon A. Raile	450,000	2,140,718	21.0
John G. Harp	450,000	2,029,859	22.2
William E. Schneider	447,400	2,165,083	20.7
Steven L. Bietz	350,000	1,597,506	21.9

Outstanding Equity Awards at Fiscal Year-End 2009

Name	Option Awards					Stock Awards			
	Number of Securities Underlying Unexercised Options Exercisable (#)	Number of Securities Underlying Unexercised Options Unexercisable (#)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Options (#)	Option Exercise Price (\$)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested (\$)	Equity Incentive Plan Awards:	Equity Incentive Plan Awards:
								Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested (\$)
	(b)	(c)	(d)	(e)	(f)	(g)(1,2)	(h)	(i)(3)	(j)(4)
Terry D. Hildestad	—	—	—	—	—	3,712	87,603	181,830	4,291,188
Vernon A. Raile	—	—	—	—	—	1,114	26,290	65,438	1,544,337
John G. Harp	—	—	—	—	—	—	—	63,055	1,488,098
William E. Schneider	—	—	—	—	—	2,970	70,092	69,354	1,636,754
Steven L. Bietz	—	—	—	—	—	558	13,169	51,545	1,216,462

(1) Adjusted for the 3-for-2 stock split effective July 26, 2006.

(2) These shares of restricted stock were granted in 2001 and vest automatically on February 15, 2010. Vesting of some or all shares may be accelerated upon change of control or if the total stockholder return equals or exceeds the 50th percentile of the performance graph peer group during the final three-year performance cycle 2007-2009. Non-preferential dividends are paid on these shares.

(3) Below is a breakdown by year of the plan awards:

Named Executive Officer	Award	Shares	End of Performance Period
Terry D. Hildestad	2007	33,091	12/31/09
	2008	39,091	12/31/10
	2009	109,648	12/31/11
Vernon A. Raile	2007	12,564	12/31/09
	2008	13,402	12/31/10
	2009	39,472	12/31/11
John G. Harp	2007	10,181	12/31/09
	2008	13,402	12/31/10
	2009	39,472	12/31/11
William E. Schneider	2007	15,119	12/31/09
	2008	14,991	12/31/10
	2009	39,244	12/31/11
Steven L. Bietz	2007	10,354	12/31/09
	2008	10,491	12/31/10
	2009	30,700	12/31/11

Shares for the 2007 award are shown at the target level (100%) based on results for the 2007-2009 performance cycle at target.

Shares for the 2008 award are shown at the target level (100%) based on results for the first two years of the 2008-2010 performance cycle at target.

Shares for the 2009 award are shown at the maximum level (200%) based on results for the first year of the 2009-2011 performance cycle above target.

(4) Value based on the number of performance shares reflected in column (i) multiplied by \$23.60, the year-end closing price for 2009.

PROXY

Option Exercises and Stock Vested during 2009

Name (a)	Option Awards		Stock Awards	
	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise (\$) (c)	Number of Shares Acquired on Vesting (#) (d)(1,2)	Value Realized on Vesting (\$) (e)(3)
Terry D. Hildestad	—	—	19,584	397,426
Vernon A. Raile	—	—	10,192	206,830
John G. Harp	—	—	8,259	167,603
William E. Schneider	—	—	12,534	254,358
Steven L. Bietz	—	—	5,755	116,789

(1) Adjusted for the 3-for-2 stock split effective July 26, 2006.

(2) Reflects performance shares for the 2006-2008 performance period that vested on February 12, 2009.

(3) Reflects the value of performance shares based on our stock price of \$18.61 on February 12, 2009, and the dividend equivalents that were paid on the vested shares.

Pension Benefits for 2009

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit (\$) (d)	Payments During Last Fiscal Year (\$) (e)
Terry D. Hildestad	Pension Plan	35	1,369,893	—
	SISP I(1)	27	1,487,740	—
	SISP II(2)	27	2,456,479	—
	SISP Excess	27	842,854	—
Vernon A. Raile	Pension Plan	30	1,033,470	—
	SISP I(1)	27	891,572	—
	SISP II(2)	27	1,899,169	—
	SISP Excess	27	—	—
John G. Harp	Pension Plan	5	172,100	—
	SISP I(1)	4	—	—
	SISP II(2)	4	1,784,336	—
	SISP Excess	4	33,837	—
	Harp Additional Retirement Benefit	4	120,136	—
William E. Schneider	Pension Plan	16	667,138	—
	SISP I(1)	15	1,081,798	—
	SISP II(2)	15	1,278,020	—
	SISP Excess	15	128,798	—
Steven L. Bietz	Pension Plan	28	675,382	—
	SISP I(1)	15	458,686	—
	SISP II(2)	15	440,819	—
	SISP Excess	15	72,082	—

(1) Grandfathered under Section 409A.

(2) Not grandfathered under Section 409A.

The amounts shown for the pension plan and excess SISP represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2009, calculated using a 5.75% discount rate, the 1994 Group Annuity Mortality Table for post-retirement mortality, and no recognition of future salary increases or pre-retirement mortality. The assumed retirement ages for these benefits was age 60 for Messrs. Harp and Bietz and age 62 for Mr. Schneider. These are the earliest ages at which the executives could begin receiving unreduced benefits. Retirement on December 31, 2009, was assumed for Messrs. Hildestad and Raile, who were age 60 and 64, respectively, on that date. The amounts shown for the SISP I and SISP II were determined using a 5.75% discount rate and assume benefits commenced at age 65. The assumptions used to calculate Mr. Harp's additional retirement benefit are described below.

Pension Plans

Messrs. Hildestad, Raile, and Harp participate in the MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees, which we refer to as our pension plan. Mr. Schneider participates in the Knife River Corporation Salaried Employees' Pension Plan, which we refer to as the KR pension plan. Mr. Bietz participates in the Williston Basin Interstate Pipeline Company Pension Plan, which we refer to

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as the WBI pension plan. Pension benefits under our pension plan and the WBI pension plan are based on the participant's average annual salary over the 60 consecutive month period in which the participant received the highest annual salary during the participant's final 10 years of service. For this purpose, only a participant's salary is considered; incentives and other forms of compensation are not included. Benefits are determined by multiplying (1) the participant's years of credited service by (2) the sum of (a) the average annual salary up to the social security integration level times 1.1% and (b) the average annual salary over the social security integration level times 1.45%. The KR pension plan uses the same formula except that 1.2% and 1.6% are used instead of 1.1% and 1.45%. The maximum years of service recognized when determining benefits under each of the pension plans is 35. Pension plan benefits are not reduced for social security benefits.

Each of the pension plans was amended to cease benefit accruals as of December 31, 2009, meaning the normal retirement benefit will not change.

To receive unreduced retirement benefits under our pension plan and the WBI pension plan, participants must either remain employed until age 60 or elect to defer commencement of benefits until age 60. Under the KR pension plan, participants must remain employed until age 62 or elect to defer commencement of benefits until age 62 to receive unreduced benefits. Messrs. Hildestad and Raile were eligible for unreduced retirement benefits under our pension plan on December 31, 2009. Participants whose employment terminates between the ages of 55 and 60, with 5 years of service, in our pension plan or the WBI pension plan and between the ages of 55 and 62, with 5 years of service, in the KR pension plan are eligible for early retirement benefits. Early retirement benefits are determined by reducing the normal retirement benefit by 0.25% per month for each month before age 60 in our pension plan and the WBI pension plan and age 62 in the KR pension plan. If a participant's employment terminates before age 55, the same reduction applies for each month the termination occurs before age 62, with the reduction capped at 21%. Messrs. Harp and Schneider are currently eligible for early retirement benefits.

Benefits for single participants under the pension plans are paid as straight life amounts and benefits for married participants are paid as actuarially reduced pensions with a survivor benefit for spouses, unless participants choose otherwise. Participants who terminate employment before age 55 may elect to receive their benefits in a lump sum. Mr. Bietz is currently eligible for a lump sum.

The Internal Revenue Code places limitations on benefit amounts that may be paid under the pension plans and on the amount of compensation that may be recognized when determining benefits. In 2009, the maximum annual benefit payable under the pension plans was \$195,000 and the maximum amount of compensation that could be recognized when determining benefits was \$245,000.

Supplemental Income Security Plan

We also offer key managers and executives, including all of our named executive officers, benefits under our nonqualified retirement plan, which we refer to as the Supplemental Income Security Plan or SISP. Benefits under the SISP consist of:

- a supplemental retirement benefit intended to augment the retirement income provided under our qualified pension plans – we refer to this benefit as the regular SISP benefit
- an excess retirement benefit relating to Internal Revenue Code limitations on retirement benefits provided under our qualified pension plans – we refer to this benefit as the excess SISP benefit, and
- death benefits – we refer to these benefits as the SISP death benefit.

Effective January 1, 2010, we amended the SISP to:

- reduce by 20% the regular SISP and death benefit levels in the benefit schedule used to determine regular SISP and death benefits for new participants and participants whose benefit levels increase on or after January 1, 2010
- impose an additional vesting period applicable to any increased regular SISP benefit and SISP death benefit occurring on or after January 1, 2010
- eliminate the excess SISP benefit for new participants and current participants who were not already eligible for the excess SISP benefit, and
- freeze excess SISP benefit accruals.

SISP benefits are forfeited if the participant's employment is terminated for cause.

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Regular SISP Benefits and Death Benefits

Regular SISP benefits and death benefits are determined by reference to one of two schedules attached to the SISP - the original schedule or the amended schedule. Our compensation committee, after receiving recommendations from our chief executive officer, determines the level at which participants are placed in the schedules. A participant's placement is generally, but not always, determined by reference to the participant's annual base salary. Benefit levels in the amended schedule which became effective on January 1, 2010, are 20% lower than the benefit levels in the original schedule. The amended schedule applies to new participants and participants who receive a benefit level increase on or after January 1, 2010.

Participants can elect to receive (1) the regular SISP benefit only, (2) the SISP death benefit only, or (3) a combination of both. Regardless of the participant's election, if the participant dies before the regular SISP benefit would commence, only the SISP death benefit is provided. If the participant elects to receive both a regular SISP benefit and a SISP death benefit, each of the benefits is reduced proportionately.

The regular SISP benefits reflected in the table above are based on the assumption that the participant elects to receive only the regular SISP benefit. The present values of the SISP death benefits that would be provided if the named executive officers were to die prior to the commencement of regular SISP benefits are reflected in the table that appears in the section entitled "Potential Payments upon Termination or Change of Control."

The SISP was amended to address changes in applicable tax laws resulting from the enactment of section 409A of the Internal Revenue Code. Regular SISP benefits that were vested as of December 31, 2004 and were thereby grandfathered under section 409A remain subject to SISP provisions then in effect, which we refer to as SISP I benefits. Regular SISP benefits that are subject to section 409A, which we refer to as SISP II benefits, are governed by amended provisions intended to comply with section 409A. Participants generally have more discretion with respect to the distributions of their SISP I benefits.

The time and manner in which the regular SISP benefits are paid depend on a variety of factors, including the time and form of benefit elected by the participant and whether the benefits are SISP I or SISP II benefits. Unless the participant elects otherwise, the SISP I benefits are paid over 180 months, with benefits commencing when the participant attains age 65 or, if later, when the participant retires. The SISP II benefits commence when the participant attains age 65 or, if later, when the participant retires, subject to a six-month delay if the participant is subject to the provisions of section 409A of the Internal Revenue Code that require delayed commencement of these types of retirement benefits. The SISP II benefits are paid over 180 months or, if commencement of payments is delayed for six months, 173 months. If the commencement of benefits is delayed for six months, the first payment includes the payments that would have been paid during the six-month period. If the participant dies after the regular SISP benefits have begun but before receipt of all of the regular SISP benefits, the remaining payments are made to the participant's designated beneficiary.

Rather than receiving their regular SISP I benefits in equal monthly installments over 15 years commencing at age 65, participants can elect a different form and time of commencement of their SISP I benefits. Participants can elect to defer commencement of the regular SISP I benefits. If this is elected, the participant retains the right to receive a monthly SISP death benefit if death occurs prior to the commencement of the regular SISP I benefit.

Participants also can elect to receive their SISP I benefits in one of three actuarially equivalent forms – a life annuity, 100% joint and survivor annuity, or a joint and two-thirds joint and survivor annuity, provided that the cost of providing these actuarial equivalent forms of benefits does not exceed the cost of providing the normal form of benefit. Neither the election to receive an actuarial equivalent benefit nor the administrator's right to pay the regular SISP benefit in the form of an actuarially equivalent lump sum are available with respect to SISP II benefits.

To promote retention, the regular SISP benefits are subject to the following ten-year vesting schedule:

- 0% vesting for less than 3 years of participation
- 20% vesting for 3 years of participation
- 40% vesting for 4 years of participation, and
- an additional 10% vesting for each additional year of participation up to 100% vesting for 10 years of participation.

In 2009, the plan was amended to impose an additional vesting requirement on benefit level increases for the regular SISP benefit granted on or after January 1, 2010. The requirement applies only to the increased benefit level. The increased benefit vests after the later of three additional years of participation in the SISP or the end of the regular vesting schedule described above. The additional three-year vesting

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requirement for benefit level increases is pro-rated for participants who are officers, attain age 65, and are required to retire, pursuant to the company's bylaws, prior to the end of the additional vesting period as follows:

- 33% of the increase vests for participants required to retire at least one year but less than two years after the increase is granted, and
- 66% of the increase vests for participants required to retire at least two years but less than three years after the increase is granted.

The benefit level increases of participants who attain age 65 and are required to retire pursuant to the company's bylaws will be further reduced to the extent the participants are not fully vested in their regular SISP benefit under the 10-year vesting schedule described above. The additional vesting period associated with a benefit level increase may be waived by the compensation committee.

SISP death benefits become fully vested if the participant dies while actively employed. Otherwise, the SISP death benefits are subject to the same vesting schedules as the regular SISP benefits.

Excess SISP Benefits

Excess SISP benefits are equal to the difference between (1) the monthly retirement benefits that would have been payable to the participant under the qualified pension plans absent the limitations under the Internal Revenue Code and (2) the actual benefits payable to the participant under the qualified pension plan. Participants are only eligible for the excess SISP benefits if (1) the participant is fully vested under the qualified pension plan, (2) the participant's employment terminates prior to age 65, and (3) benefits under the qualified pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation. Effective January 1, 2005, participants who were not then vested in the excess SISP benefits were also required to remain actively employed by the company until age 60. In 2009, the plan was amended to limit eligibility of the excess SISP benefit to current SISP participants (1) who are already vested in the excess SISP benefit or (2) who will become vested in the excess SISP benefits if they remain employed with the company until age 60. The plan was further amended to freeze the excess SISP benefits to a maximum of the benefit level payable based on the participant's years of service and compensation level as of December 31, 2009. With the exception of Mr. Harp, each of the named executive officers would be entitled to the excess SISP benefit if they were to terminate employment prior to age 65. Mr. Harp must remain employed until age 60 to become entitled to his excess SISP benefit.

Benefits generally commence six months after the participant's employment terminates and continue to age 65 or until the death of the participant, if prior to age 65. If a participant who dies prior to age 65 elected a joint and survivor benefit, the survivor's excess SISP benefit is paid until the date the participant would have attained age 65.

Mr. Harp's Additional Retirement Benefit

To encourage Mr. Harp to remain with the company, on November 16, 2006, upon recommendation of our chief executive officer and the compensation committee, our board of directors approved an additional retirement benefit for Mr. Harp. The benefit provides for Mr. Harp to receive payments that represent the equivalent of an additional three years of service under our pension plan, the excess SISP, and the SISP. The additional three years of service recognize Mr. Harp's previous employment with a subsidiary of the company. To calculate payments Mr. Harp could receive due to his additional retirement benefit, we applied the additional years of service to each of the retirement arrangements and assumed he remained employed until age 60, for purposes of calculating the additional benefit under the pension plan and excess SISP, and age 65, for purposes of calculating the additional benefit under the SISP II. Because Mr. Harp would be fully vested in the SISP II benefit if he retired at age 65, the additional years of service provided by the agreement would not increase his SISP II benefit. Consequently, the amount shown in the table does not include any additional benefit attributable to the SISP II. If Mr. Harp were to retire before achieving 10 years of service and becoming fully vested in his SISP II benefit, the additional years of service provided by the additional retirement benefit would increase his vesting percentage under the SISP II and therefore would result in an additional payment. For a description of the payments that could be provided under the additional retirement benefit if Mr. Harp's employment were to be terminated on December 31, 2009, refer to the table and related notes in "Potential Payment upon Termination or Change of Control" below.

The SISP also provides that if a participant becomes totally disabled, the participant will continue to receive credit for up to two additional years under the SISP as long as the participant is totally disabled during such time. Since the named executive officers other than Mr. Harp are fully vested in their SISP benefits, this would not result in any incremental benefit for the named executive officers other than Mr. Harp. The present value of these two additional years of service for Mr. Harp is reflected in the table that appears in the section entitled "Potential Payments upon Termination or Change of Control."

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Nonqualified Deferred Compensation for 2009

Name (a)	Executive Contributions in Last FY (\$) (b)	Registrant Contributions in Last FY (\$) (c)	Earnings in Aggregate Last FY (\$) (d)	Aggregate Withdrawals/ Distributions (\$) (e)	Aggregate Balance at Last FYE (\$) (f)
Terry D. Hildestad	—	—	52,314	—	835,932
Vernon A. Raile	—	—	94,556	—	1,510,791
John G. Harp	—	—	—	—	—
William E. Schneider	—	—	83,840	—	1,339,689(1)
Steven L. Bietz	—	—	—	—	—

(1) Includes \$392,000, which was reported in the Summary Compensation Table for 2006 in column (g).

Participants in the executive incentive compensation plans may elect to defer up to 100% of their annual incentive awards. Deferred amounts accrue interest at a rate determined annually by the compensation committee. The interest rate in effect for 2009 was 6.48% or the "Moody's Rate," which was defined by reference to the U.S. Long-Term Corporate Bond Yield Average for "A" rated companies. Effective January 1, 2009, "Moody's Rate" is the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "A" rated companies as of the last business day of each month for the 12-month period ending October 31, 2008, and dividing by 12. The deferred amount will be paid in accordance with the participant's election, following termination of employment or beginning in the fifth year following the year the award was granted. The amounts will be paid in accordance with the participant's election in a lump sum or in monthly installments not to exceed 120 months. In the event of a change of control, all amounts become immediately payable.

A change of control is defined as

- an acquisition during a 12-month period of 30% or more of the total voting power of our stock
- an acquisition of our stock that, together with stock already held by the acquirer, constitutes more than 50% of the total fair market value or total voting power of our stock
- replacement of a majority of the members of our board of directors during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of our board of directors or
- acquisition of our assets having a gross fair market value at least equal to 40% of the total gross fair market value of all of our assets.

Potential Payments upon Termination or Change of Control

The following tables show the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios and upon a change of control. The information assumes the terminations and the change of control occurred on December 31, 2009. All of the payments and benefits described below would be provided by the company or its subsidiaries.

The tables exclude base salary, 2009 annual incentives, stock awards the named executive officers earned due to employment through December 31, 2009, and compensation and benefits provided under plans or arrangements that do not discriminate in favor of the named executive officers and that are generally available to all salaried employees, such as benefits under our qualified defined benefit pension plan, accrued vacation pay, continuation of health care benefits, and life insurance benefits. The tables also do not include the named executive officers' benefits under our nonqualified deferred compensation plans that are reported in the Nonqualified Deferred Compensation for 2009 table. See the Pension Benefits for 2009 table and the Nonqualified Deferred Compensation for 2009 table, and accompanying narratives, for a description of the named executive officers' accumulated benefits under our qualified defined benefit pension plans and our nonqualified deferred compensation plans.

We provide disability benefits to some of our salaried employees equal to 60% of their base salary, subject to a cap on the amount of base salary taken into account when calculating benefits. For officers, the limit on base salary is \$200,000. For other salaried employees, the limit is \$100,000. For all salaried employees, disability payments continue until age 65 if disability occurs at or before age 60 and for 5 years if disability occurs between the ages of 60 and 65. Disability benefits are reduced for amounts paid as retirement benefits. The amounts in the tables reflect the present value of the disability benefits attributable to the additional \$100,000 of base salary recognized for executives under our disability program, subject to the 60% limitation, after reduction for amounts that would be paid as retirement benefits. The present value of the disability benefits was determined using a discount rate of 5.75%. As the tables reflect, with the exception of Mr. Harp, the reduction for amounts paid as retirement benefits would eliminate disability benefits assuming a termination of employment on December 31, 2009.

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Upon a change of control, share-based awards granted under our Long-Term Performance-Based Incentive Plan vest and non-share-based awards are paid in cash. All shares of restricted stock would vest in full upon a change of control. All performance share awards would vest at their target levels. For this purpose, the term change of control is defined as:

- the acquisition by an individual, entity, or group of 20% or more of our outstanding voting securities
- a turnover in a majority of our board of directors without the approval of a majority of the members of the board who were members of the board as of the plan's effective date or whose election was approved by such board members
- consummation of a merger or consolidation or sale or other disposition of all or substantially all of the company's assets, unless the company's stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding shares and voting power of the resulting corporation after the merger or the corporation that acquires the company's assets, as the case may be or
- stockholder approval of the company's liquidation or dissolution.

Shares of restricted stock and associated dividends are forfeited upon termination of employment. Performance shares are forfeited if termination of employment occurs during the first year of the performance period. If a termination of employment occurs for a reason other than cause, performance share awards granted prior to 2009 are prorated as follows:

- if the termination of employment occurs during the second year of the performance period, the executive receives a prorated portion of any performance shares earned based on the number of months employed during the performance period and
- if the termination of employment occurs during the third year of the performance period, the executive receives the full amount of any performance shares earned.

Beginning with performance share awards granted in 2009, these awards will be forfeited if the participant's employment terminates for any reason before the participant has reached age 55 and completed 10 years of service. Performance shares and related dividend equivalents for those participants whose employment is terminated after the participant has reached age 55 and completed 10 years of service will be prorated as described above.

Accordingly, if a December 31, 2009 termination is assumed, the named executive officers' 2009-2011 performance share awards would be forfeited, any amounts earned under the 2008-2010 performance share awards would be reduced by one-third, and any amounts earned under the 2007-2009 performance share awards would not be reduced. The number of performance shares earned depends on actual performance through the full performance period. As actual performance for the 2007-2009 performance share awards has been determined, the amounts for these awards in the event of a non-change of control termination were based on actual performance, which resulted in vesting of 100% of the target award. Amounts for the 2008-2010 performance share awards are also shown at target, based upon assumed target performance. No amounts are shown for the 2009-2011 performance share awards because such awards would be forfeited. Although vesting would only occur after completion of the performance period, the amounts shown in the tables were not reduced to reflect the present value of the performance shares that could vest. Dividend equivalents attributable to earned performance shares would also be paid. Dividend equivalents accrued through December 31, 2009 are included in the amounts shown.

The value of the vesting of shares of restricted stock and performance shares shown in the tables was determined by multiplying the number of shares of restricted stock or performance shares that would vest upon termination or a change of control by the closing price of our stock on December 31, 2009.

We also have change of control employment agreements with our named executive officers and other executives, which provide certain protections to the executives in the event there is a change of control of the company.

For these purposes, we define "change of control" as:

- the acquisition by an individual, entity, or group of 20% or more of our voting securities
- a turnover in a majority of our board of directors without the approval of a majority of the members of the board who were members of the board as of the agreement date or whose election was approved by such board members
- consummation of a merger or consolidation, unless our stockholders immediately prior to the merger beneficially own more than 60% of the outstanding shares and voting power of the resulting corporation after the merger or
- stockholder approval of our liquidation or dissolution.

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If a change of control occurs, the agreements provide for a three-year employment period from the date of the change of control, during which the named executive officer is entitled to receive:

- a base salary of not less than twelve times the highest monthly salary paid within the preceding twelve months
- annual incentive opportunity of not less than the highest annual incentive paid in any of the three years before the change of control
- participation in our incentive, savings, retirement, and welfare benefit plans
- reasonable vehicle allowance, home office allowance, and subsidized annual physical examinations and
- office and support staff, vacation, and expense reimbursement consistent with such benefits as they were provided before the change of control.

Assuming a change of control occurred on December 31, 2009, the guaranteed minimum level of base salary provided over the three-year employment period would not result in an increase in any of the named executive officers' base salaries. The minimum annual incentive amounts Messrs. Hildestad, Raile, Harp, Schneider, and Bietz would be entitled to over the three-year employment period would be \$1,500,000, \$585,000, \$720,000, \$581,620, and \$450,450, respectively. The agreements also provide that severance payments and benefits will be provided:

- if we terminate the named executive officer's employment during the employment period, other than for cause or disability, or
- the named executive officer resigns for good reason.

"Cause" means the named executive officer's willful and continued failure to substantially perform his duties or willfully engaging in illegal conduct or gross misconduct materially injurious to the company. "Good reason" includes:

- a material diminution of the named executive officer's authority, duties, or responsibilities
- a material change in the named executive officer's work location and
- our material breach of the agreement.

In such event, the named executive officer would receive:

- accrued but unpaid base salary and accrued but unused vacation
- a lump sum payment equal to three times his (a) annual salary using the higher of the then current annual salary or twelve times the highest monthly salary paid within the twelve months before the change of control and (b) annual incentive using the highest annual incentive paid in any of the three years before the change of control or, if higher, the annual incentive for the most recently completed fiscal year
- a pro-rated annual incentive for the year of termination
- an amount equal to the actuarial equivalent of the additional benefit the named executive officer would receive under the SISP and any other supplemental or excess retirement plan if employment continued for an additional three years
- outplacement benefits and
- a payment equal to any federal excise tax on excess parachute payments if the total parachute payments exceed 110% of the safe harbor amount for that tax. If this 110% threshold is not exceeded, the named executive officer's payments and benefits would be reduced to avoid the tax. The named executive officers are not reimbursed for any taxes imposed on this tax reimbursement payment.

This description of severance payments and benefits reflects the terms of the agreements as in effect on December 31, 2009.

The compensation committee may also consider providing severance benefits on a case-by-case basis for employment terminations not related to a change of control. The compensation committee adopted a checklist of factors in February 2005 to consider when determining whether any such severance benefits should be paid. The tables do not reflect any such severance benefits, as these benefits are made in the discretion of the committee on a case-by-case basis and it is not possible to estimate the severance benefits, if any, that would be paid.

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Terry D. Hildestad

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination (\$)	Not for Cause Termination (\$)	For Cause Termination (\$)	Death (\$)	Disability (\$)	Not for Cause or Good Reason Termination Following Change of Control (\$)	Change of Control (Without Termination) (\$)
Compensation:							
Base Salary						2,250,000	
Short-term Incentive(1)						6,000,000	
2007-2009 Performance Shares	836,653	836,653		836,653	836,653	836,653	836,653
2008-2010 Performance Shares	645,270	645,270		645,270	645,270	967,893	967,893
2009-2011 Performance Shares						1,326,741	1,326,741
Restricted Stock						87,603	87,603
Benefits and Perquisites:							
Regular SISP(2)	3,944,219	3,944,219			3,944,219	3,944,219	
Excess SISP(3)	842,838	842,838			842,838	842,838	
SISP Death Benefits(4)				10,335,773			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(5)						1,940,878	
Total	6,268,980	6,268,980		11,817,696	6,268,980	18,246,825	3,218,890

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the present value of Mr. Hildestad's vested regular SISP benefit as of December 31, 2009, which was \$42,710 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Hildestad's change of control agreement would not increase the actuarial present value of his SISP amount.

(3) Represents the present value of all excess SISP benefits Mr. Hildestad would be entitled to upon termination of employment under the SISP. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of employment assumed for purposes of calculating the additional retirement plan payment under Mr. Hildestad's change of control agreement would not increase the actuarial present value of his excess SISP benefits.

(4) Represents the present value of 180 monthly payments of \$85,420 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(5) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

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Vernon A. Raile

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination (\$)	Not for Cause Termination (\$)	For Cause Termination (\$)	Death (\$)	Disability (\$)	Not for Cause or Good Reason Termination Following Change of Control (\$)	Change of Control (Without Termination) (\$)
Compensation:							
Base Salary						1,350,000	
Short-term Incentive(1)						2,340,000	
2007-2009 Performance Shares	317,661	317,661		317,661	317,661	317,661	317,661
2008-2010 Performance Shares	221,231	221,231		221,231	221,231	331,834	331,834
2009-2011 Performance Shares						477,611	477,611
Restricted Stock						26,290	26,290
Benefits and Perquisites:							
Regular SISP(2)	2,790,741	2,790,741			2,790,741	2,790,741	
SISP Death Benefits(3)				5,529,675			
Disability Benefits						50,000	
Outplacement Services						856,992	
280G Tax(4)							
Total	3,329,633	3,329,633		6,068,567	3,329,633	8,541,129	1,153,396

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the present value of Mr. Raile's vested regular SISP benefit as of December 31, 2009, which was \$22,850 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Raile's change of control agreement would not increase the actuarial present value of his SISP amount.

(3) Represents the present value of 180 monthly payments of \$45,700 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(4) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

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John G. Harp

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination (\$)	Not for Cause Termination (\$)	For Cause Termination (\$)	Death (\$)	Disability (\$)	Not for Cause or Good Reason Termination Following Change of Control (\$)	Change of Control (Without Termination) (\$)
Compensation:							
Base Salary						1,350,000	
Short-term Incentive(1)						2,880,000	
2007-2009 Performance Shares	257,410	257,410		257,410	257,410	257,410	257,410
2008-2010 Performance Shares	221,231	221,231		221,231	221,231	331,834	331,834
2009-2011 Performance Shares						477,611	477,611
Restricted Stock							
Benefits and Perquisites:							
Incremental Pension(2)	107,307	107,307			107,307	107,307	
Regular SISP	1,249,035(3)	1,249,035(3)			1,603,546(4)	1,784,336(5)	
Excess SISP(6)						193,615	
SISP Death Benefits(7)				5,529,675			
Disability Benefits(8)					227,839		
Outplacement Services						50,000	
280G Tax(9)						1,068,156	
Total	1,834,983	1,834,983		6,008,316	2,417,333	8,500,269	1,066,855

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the equivalent of three additional years of service that would be provided under the Harp additional retirement benefit described following the Pension Benefits for 2009 table. Present value was determined using a 5.75% discount rate.

(3) Represents the present value of Mr. Harp's vested regular SISP benefit as of December 31, 2009, which was \$15,995 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. Also includes the additional benefit attributable to three additional years of service that would be provided under the retirement benefit agreement described following the Pension Benefits for 2009 table.

(4) Represents the present value of Mr. Harp's vested SISP benefit described in footnote 3, adjusted to reflect the increase in the present value of his regular SISP benefit that would result from an additional two years of vesting under the SISP. Present value was determined using a 5.75% discount rate.

(5) Represents the present value of Mr. Harp's vested SISP benefit described in footnote 3, adjusted to reflect the increase in the present value of his regular SISP benefit that would result if he continued employment for an additional three years. Present value was determined using a 5.75% discount rate.

(6) Represents the present value of all excess SISP benefits Mr. Harp would be entitled to, calculated with the assumption of three additional years of employment, as provided under Mr. Harp's change of control agreement. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 table.

(7) Represents the present value of 180 monthly payments of \$45,700 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(8) Represents the present value of the disability benefit after reduction for amounts that would be paid as retirement benefits. Present value was determined using a 5.75% discount rate.

(9) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

PROXY

William E. Schneider

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination (\$)	Not for Cause Termination (\$)	For Cause Termination (\$)	Death (\$)	Disability (\$)	Not for Cause or Good Reason Termination Following Change of Control (\$)	Change of Control (Without Termination) (\$)
Compensation:							
Base Salary						1,342,200	
Short-term Incentive(1)						2,326,480	
2007-2009 Performance Shares	382,260	382,260		382,260	382,260	382,260	382,260
2008-2010 Performance Shares	247,451	247,451		247,451	247,451	371,177	371,177
2009-2011 Performance Shares						474,852	474,852
Restricted Stock						70,092	70,092
Benefits and Perquisites:							
Regular SISP(2)	2,359,818	2,359,818			2,359,818	2,359,818	
Excess SISP(3)	126,868	126,868			126,868	126,868	
SISP Death Benefits(4)				5,529,675			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(5)						808,830	
Total	3,116,397	3,116,397		6,159,386	3,116,397	8,312,577	1,298,381

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the present value of Mr. Schneider's vested regular SISP benefit as of December 31, 2009, which was \$22,850 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Schneider's change of control agreement would not increase the actuarial present value of his SISP amount.

(3) Represents the present value of all excess SISP benefits Mr. Schneider would be entitled to upon termination of employment under the SISP. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of employment assumed for purposes of calculating the additional retirement plan payment under Mr. Schneider's change of control agreement would not increase the actuarial present value of his excess SISP benefits.

(4) Represents the present value of 180 monthly payments of \$45,700 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(5) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

PROXY

Proxy Statement

Steven L. Bietz

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination (\$)	Not for Cause Termination (\$)	For Cause Termination (\$)	Death (\$)	Disability (\$)	Not for Cause or Good Reason Termination Following Change of Control (\$)	Change of Control (Without Termination) (\$)
Compensation:							
Base Salary						1,050,000	
Short-term Incentive(1)						1,801,800	
2007-2009 Performance Shares	261,784	261,784		261,784	261,784	261,784	261,784
2008-2010 Performance Shares	173,171	173,171		173,171	173,171	259,757	259,757
2009-2011 Performance Shares						371,470	371,470
Restricted Stock						13,169	13,169
Benefits and Perquisites:							
Regular SISP(2)	899,505	899,505			899,505	899,505	
Excess SISP	146,033(3)	146,033(3)			146,033(3)	388,504(4)	
SISP Death Benefits(5)				3,898,602			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(6)						671,881	
Total	1,480,493	1,480,493		4,333,557	1,480,493	5,767,870	906,180

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the present value of Mr. Bietz's vested regular SISP benefit as of December 31, 2009, which was \$16,110 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Bietz's change of control agreement would not increase the actuarial present value of his SISP amount.

(3) Represents the present value of all excess SISP benefits Mr. Bietz would be entitled to upon termination of employment under the SISP. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 table.

(4) Represents the present value of all excess SISP benefits Mr. Bietz would be entitled to, calculated with the assumption of three additional years of employment, as provided under Mr. Bietz's change of control agreement. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 table.

(5) Represents the present value of 180 monthly payments of \$32,220 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(6) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

PROXY

Director Compensation for 2009

Name (a)	Fees Earned or Paid in Cash (\$) (b)	Stock Awards (\$) (c)(1)	Option Awards (\$) (d)	Non-Equity Incentive Plan Compensation (\$) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (\$) (f)	All Other Compensation (\$) (g)(2)	Total (\$) (h)
Thomas Everist	57,083	69,445	-(3)	-	-	174	126,702
Karen B. Fagg	55,250(4)	69,445	-	-	-	174	124,869
A. Bart Holaday	50,583	69,445	-	-	-	174	120,202
Dennis W. Johnson	59,083	69,445	-	-	-	174	128,702
Thomas C. Knudson	52,083	69,445	-	-	-	174	121,702
Richard H. Lewis	55,083	69,445	-	-	-	174	124,702
Patricia L. Moss	52,083(5)	69,445	-	-	-	174	121,702
John L. Olson	40,083(6)	69,445	-(7)	-	-	563,060(9)	672,588
Harry J. Pearce	130,000	69,445	-(8)	-	-	174	199,619
Sister Thomas Welder	50,583	69,445	-	-	-	174	120,202
John K. Wilson	53,583(10)	69,445	-	-	-	174	123,202

(1) Valued based on \$17.147, the purchase price of the stock on the date of grant, May 18, 2009, which is the grant date fair value.

(2) Group life insurance premiums, except for Mr. Olson.

(3) Mr. Everist had 18,562 stock options outstanding as of December 31, 2009.

(4) Includes \$17,984 that Ms. Fagg received in our common stock in lieu of cash.

(5) Includes \$52,064 that Ms. Moss received in our common stock in lieu of cash.

(6) Mr. Olson retired on August 13, 2009.

(7) Mr. Olson had 18,562 stock options outstanding as of December 31, 2009.

(8) Mr. Pearce had 13,500 stock options outstanding as of December 31, 2009.

(9) Comprised of a group life insurance premium of \$116 and the value of Mr. Olson's deferred compensation at December 31, 2009, which is payable over five years in monthly installments.

(10) Includes \$44,578 that Mr. Wilson received in our common stock in lieu of cash.

Effective June 1, 2009, the board approved changes to the MDU Resources Group, Inc. Directors' Compensation Policy, and the following table shows the cash and stock retainers payable to our non-employee directors.

	Effective June 1, 2009	Prior to June 1, 2009
Base Retainer	\$55,000	\$ 30,000
Additional Retainers:		
Non-Executive Chairman	75,000(2)	100,000(1)(2)
Lead Director, if any	33,000	33,000
Audit Committee Chairman	10,000	10,000
Compensation Committee Chairman	5,000	5,000
Nominating and Governance Committee Chairman	5,000	5,000
Meeting Fees:		
Board Meeting	-	1,500
Committee Meeting	-	1,500
Annual Stock Retainer	4,050 shares	4,050 shares

(1) \$50,000 of this amount was paid in company common stock prior to January 1, 2009.

(2) The Non-Executive Chairman does not receive board or committee meeting fees.

In addition to liability insurance, we maintain group life insurance in the amount of \$100,000 on each non-employee director for the benefit of each director's beneficiaries during the time each director serves on the board. The annual cost per director is \$174.

Directors may defer all or any portion of the annual cash retainer, meeting fees, if any, and any other cash compensation paid for service as a director pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board.

Directors are reimbursed for all reasonable travel expenses including spousal expenses in connection with attendance at meetings of the board and its committees. All amounts together with any other perquisites were below the disclosure threshold for 2009.

Proxy Statement

Our post-retirement income plan for directors was terminated in May 2001 for current and future directors. The net present value of each director's benefit was calculated and converted into phantom stock. Payment is deferred pursuant to the Deferred Compensation Plan for Directors and will be made in cash over a five-year period after the director's retirement from the board.

The board adopted stock ownership guidelines for directors in November 2005. Each director is expected to own our common stock equal in value to five times the director's base retainer. A director, with good cause and with the knowledge of the board, may donate or assign all of the director's company common stock to a charitable, religious, or non-profit organization in lieu of ownership. Shares acquired through purchases on the open market and participation in our director stock plans will be considered in ownership calculations as will ownership of our common stock by a spouse. A director is allowed five years commencing January 1 of the year following the year of that director's initial election to the board to meet the guideline requirements. The level of common stock ownership is monitored with an annual report made to the compensation committee of the board. For stock ownership, please see "Security Ownership."

In our Director Compensation Policy, we prohibit our directors from hedging their ownership of company common stock. Directors may not enter into transactions that allow the director to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership.

Narrative Disclosure of our Compensation Policies and Practices as They Relate to Risk Management

We have reviewed our compensation policies and practices for all employees and concluded that any risks arising from our policies and programs are not reasonably likely to have a material adverse effect on our company.

PROXY

BALANCE SHEET

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	Assets and Other Debits			
2	Utility Plant			
3	101 Electric Plant in Service	\$736,893,792	\$777,621,714	5.53%
4	101.1 Property Under Capital Leases			
5	102 Electric Plant Purchased or Sold			
6	104 Electric Plant Leased to Others			
7	105 Electric Plant Held for Future Use			
8	106 Completed Constr. Not Classified - Electric			
9	107 Construction Work in Progress - Electric	50,812,067	103,058,636	102.82%
10	108 (Less) Accumulated Depreciation	(403,399,367)	(419,780,203)	4.06%
11	111 (Less) Accumulated Amortization	(4,705,268)	(5,139,599)	9.23%
12	114 Electric Plant Acquisition Adjustments	10,387,642	10,387,642	0.00%
13	115 (Less) Accum. Amort. Electric Plant Acq. Adj.	(9,234,596)	(9,462,839)	2.47%
14	120 Nuclear Fuel (Net)			
15	Other Utility Plant	380,968,710	385,933,227	1.30%
16	Accum. Depr. and Amort. - Other Util. Plant	(206,061,656)	(211,783,684)	2.78%
17	TOTAL Utility Plant	\$555,661,324	\$630,834,894	13.53%
18	Other Property & Investments			
19	121 Nonutility Property	\$3,707,024	\$4,065,076	9.66%
20	122 (Less) Accum. Depr. & Amort. of Nonutil. Prop.	(1,117,112)	(1,207,227)	8.07%
21	123 Investments in Associated Companies			
22	123.1 Investments in Subsidiary Companies	2,478,164,341	2,240,332,380	-9.60%
23	124 Other Investments	35,032,098	41,701,031	19.04%
24	125 Sinking Funds			
25	TOTAL Other Property & Investments	\$2,515,786,351	\$2,284,891,260	-9.18%
26	Current & Accrued Assets			
27	131 Cash	\$181,115	\$5,039,802	2682.65%
28	132-134 Special Deposits	1,200	1,200	0.00%
29	135 Working Funds	113,921	63,569	-44.20%
30	136 Temporary Cash Investments	1,938,468	25,000,000	1189.68%
31	141 Notes Receivable			
32	142 Customer Accounts Receivable	29,930,415	26,120,425	-12.73%
33	143 Other Accounts Receivable	2,394,649	3,182,572	32.90%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(285,809)	(233,779)	-18.20%
35	145 Notes Receivable - Associated Companies	57,000,000	0	-100.00%
36	146 Accounts Receivable - Associated Companies	26,427,125	33,121,406	25.33%
37	151 Fuel Stock	4,099,005	4,613,409	12.55%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals and Extracted Products			
40	154 Plant Materials and Operating Supplies	10,225,093	9,812,475	-4.04%
41	155 Merchandise	1,742,091	974,586	-44.06%
42	156 Other Material & Supplies			
43	163 Stores Expense Undistributed		(1,699)	
44	164.1 Gas Stored Underground - Current	8,529,714	17,640,699	106.81%
45	165 Prepayments	4,865,549	4,950,903	1.75%
46	166 Advances for Gas Explor., Devl. & Production			
47	171 Interest & Dividends Receivable		139	
48	172 Rents Receivable			
49	173 Accrued Utility Revenues	46,729,484	35,878,909	-23.22%
50	174 Miscellaneous Current & Accrued Assets	2,560	0	-100.00%
51	TOTAL Current & Accrued Assets	\$193,894,580	\$166,164,616	-14.30%

BALANCE SHEET

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	Assets and Other Debits (cont.)			
2				
3	Deferred Debits			
4				
5	181 Unamortized Debt Expense	\$1,191,582	\$1,217,947	2.21%
6	182.1 Extraordinary Property Losses			
7	182.2 Unrecovered Plant & Regulatory Study Costs			
8	182.3 Other Regulatory Assets	88,196,422	80,661,452	-8.54%
9	183 Prelim. Electric Survey & Investigation Chrg.	579,901	283,502	-51.11%
10	183.1 Prelim. Nat. Gas Survey & Investigation Chrg.	0	0	0.00%
11	183.2 Other Prelim. Nat. Gas Survey & Invtg. Chrgs.	2,084	0	-100.00%
12	184 Clearing Accounts	(191,726)	(232,048)	21.03%
13	185 Temporary Facilities			
14	186 Miscellaneous Deferred Debits	26,229,986	22,623,810	-13.75%
15	187 Deferred Losses from Disposition of Util. Plant			
16	188 Research, Devel. & Demonstration Expend.			
17	189 Unamortized Loss on Reacquired Debt	9,990,648	10,285,123	2.95%
18	190 Accumulated Deferred Income Taxes	60,304,833	55,095,783	-8.64%
19	191 Unrecovered Purchased Gas Costs	24,225,488	(9,339,438)	-138.55%
20	192.1 Unrecovered Incremental Gas Costs			
21	192.2 Unrecovered Incremental Surcharges			
22	TOTAL Deferred Debits	\$210,529,218	\$160,596,131	-23.72%
23				
24	TOTAL ASSETS & OTHER DEBITS	\$3,475,871,473	\$3,242,486,901	-6.71%
	Account Number & Title	Last Year	This Year	% Change
25	Liabilities and Other Credits			
26				
27	Proprietary Capital			
28				
29	201 Common Stock Issued	\$184,208,283	\$188,389,265	2.27%
30	202 Common Stock Subscribed			
31	204 Preferred Stock Issued	15,000,000	15,000,000	0.00%
32	205 Preferred Stock Subscribed			
33	207 Premium on Capital Stock	941,909,202	1,019,788,138	8.27%
34	211 Miscellaneous Paid-In Capital			
35	213 (Less) Discount on Capital Stock			
36	214 (Less) Capital Stock Expense	(3,610,416)	(4,110,305)	13.85%
37	216 Appropriated Retained Earnings	436,608,753	472,482,478	8.22%
38	216.1 Unappropriated Retained Earnings	1,180,220,338	904,556,156	-23.36%
39	217 (Less) Reacquired Capital Stock	(3,625,813)	(3,625,813)	0.00%
40	219 Accumulated Other Comprehensive Income	10,365,311	(20,832,825)	-300.99%
41	TOTAL Proprietary Capital	\$2,761,075,658	\$2,571,647,094	-6.86%
42				
43	Long Term Debt			
44				
45	221 Bonds	\$235,500,000	\$280,000,000	18.90%
46	222 (Less) Reacquired Bonds			
47	223 Advances from Associated Companies			
48	224 Other Long Term Debt	80,708,867	1,102,591	-98.63%
49	225 Unamortized Premium on Long Term Debt			
50	226 (Less) Unamort. Discount on Long Term Debt-Dr.	(1,837)	0	-100.00%
51	TOTAL Long Term Debt	\$316,207,030	\$281,102,591	-11.10%

BALANCE SHEET

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1				
2	Total Liabilities and Other Credits (cont.)			
3				
4	Other Noncurrent Liabilities			
5				
6	227 Obligations Under Cap. Leases - Noncurrent			
7	228.1 Accumulated Provision for Property Insurance			
8	228.2 Accumulated Provision for Injuries & Damages	\$1,582,142	\$1,486,612	-6.04%
9	228.3 Accumulated Provision for Pensions & Benefits	59,371,415	54,313,944	-8.52%
10	228.4 Accumulated Misc. Operating Provisions			
11	229 Accumulated Provision for Rate Refunds			
12	230 Asset Retirement Obligations	2,691,414	3,302,103	22.69%
13	TOTAL Other Noncurrent Liabilities	\$63,644,971	\$59,102,659	-7.14%
14				
15	Current & Accrued Liabilities			
16				
17	231 Notes Payable			
18	232 Accounts Payable	33,220,974	30,573,900	-7.97%
19	233 Notes Payable to Associated Companies			
20	234 Accounts Payable to Associated Companies	7,119,598	5,802,650	-18.50%
21	235 Customer Deposits	2,408,988	2,239,734	-7.03%
22	236 Taxes Accrued	(840,838)	14,803,275	1860.54%
23	237 Interest Accrued	4,206,271	5,058,554	20.26%
24	238 Dividends Declared	28,639,606	29,748,761	3.87%
25	239 Matured Long Term Debt			
26	240 Matured Interest			
27	241 Tax Collections Payable	1,578,001	1,986,880	25.91%
28	242 Miscellaneous Current & Accrued Liabilities	25,765,992	24,937,206	-3.22%
29	243 Obligations Under Capital Leases - Current			
30	TOTAL Current & Accrued Liabilities	\$102,098,592	\$115,150,960	12.78%
31				
32	Deferred Credits			
33				
34	252 Customer Advances for Construction	\$5,289,755	\$5,924,550	12.00%
35	253 Other Deferred Credits	101,962,554	81,150,481	-20.41%
36	254 Other Regulatory Liabilities	9,003,884	8,593,585	-4.56%
37	255 Accumulated Deferred Investment Tax Credits	361,334	162,069	-55.15%
38	256 Deferred Gains from Disposition Of Util. Plant			
39	257 Unamortized Gain on Reacquired Debt			
40	281-283 Accumulated Deferred Income Taxes	116,227,695	119,652,912	2.95%
41	TOTAL Deferred Credits	\$232,845,222	\$215,483,597	-7.46%
42				
43	TOTAL LIABILITIES & OTHER CREDITS	\$3,475,871,473	\$3,242,486,901	-6.71%

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2009	2009/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**Note 1 - Summary of Significant Accounting Policies****Basis of presentation**

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

The financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. These requirements differ from generally accepted accounting principles (GAAP) related to the presentation of certain items including, but not limited to, the current portion of long-term debt, deferred income taxes, cost of removal liabilities, and current unrecovered purchased gas costs.

The Respondent owns two wholly owned subsidiaries, Centennial Energy Holdings, Inc. and MDU Energy Capital, LLC. As required by the FERC for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investments using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by \$1.1 billion; current and accrued assets would increase by \$895.5 million; deferred debits would increase by \$729.2 million; long-term debt would increase by \$1.2 billion; other noncurrent liabilities and current and accrued liabilities would increase by \$492.9 million; deferred credits would increase by \$1.0 billion as of December 31, 2009. Furthermore, operating revenues would increase by \$3.7 billion and operating expenses, excluding income taxes, would increase by \$3.9 billion for the twelve months ended December 31, 2009. In addition, net cash provided by operating activities would increase by \$623.3 million; net cash used in investing activities would increase by \$322.8 million; net cash used in financing activities would increase by \$205.8 million; the effect of exchange rate changes on cash would increase by \$782,000; and the net change in cash and cash equivalents would be a increase of \$95.5 million for the twelve months ended December 31, 2009. Reporting its subsidiary investments using the equity method rather than GAAP has no effect on net income or retained earnings.

The Company's notes to the financial statements are presented consolidated with its subsidiary investments and prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of the Company's FERC basis financial statements contained herein.

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.		12/31/2009	2009/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

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

Cash and cash equivalents

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

Allowance for doubtful accounts

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

Natural gas in storage

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

Inventories

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

Investments

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

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described in natural gas and oil properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was \$11.5 million, \$9.0 million and \$7.1 million in 2009, 2008 and 2007, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except

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for depletable aggregate reserves, which are depleted based on the units-of-production method, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

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

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

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

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

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Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No significant impairment losses were recorded in 2009, 2008 and 2007. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. For more information on goodwill, see Note 5.

Natural gas and oil properties

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

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. Prior to that date, if capitalized costs exceeded the full-cost ceiling at the end of any quarter, a permanent noncash write-down was required to be charged to earnings in that quarter unless subsequent price changes eliminated or reduced an indicated write-down. Effective December 31, 2009, if capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

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

The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized additional write-downs of its natural gas and oil properties of \$107.9 million (\$66.9 million after tax) at March 31, 2009, and \$79.2 million (\$49.1 million after tax) at December 31, 2008, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 7.

At December 31, 2009, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to

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December 31, 2009, could result in a future write-down of the Company's natural gas and oil properties.

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

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

Costs not subject to amortization as of December 31, 2009, consisted primarily of unevaluated leaseholds, drilling costs, seismic costs and capitalized interest associated primarily with natural gas and oil development in the Paradox Basin in Utah; Big Horn Basin in Wyoming; east Texas properties; and CBNG in the Powder River Basin of Wyoming and Montana. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was \$92.6 million and \$123.2 million at December 31, 2009 and 2008, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from natural gas and oil production properties only on that portion of production sold and allocable to the Company's ownership interest in the related well. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs and estimated earnings in excess of billings on uncompleted contracts of \$28.8 million and \$40.1 million at December 31, 2009 and 2008, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of \$49.3 million and \$106.9 million at December 31, 2009 and 2008, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to \$45.4 million and \$86.9 million at December 31, 2009 and 2008, respectively. The amounts expected to be paid within one year or less are included in

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receivables, net, and amounted to \$44.0 million and \$67.7 million at December 31, 2009 and 2008, respectively. The long-term retainage which was included in deferred charges and other assets - other was \$1.4 million and \$19.2 million at December 31, 2009 and 2008, respectively.

Derivative instruments

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

The Company's policy generally allows the hedging of monthly forecasted natural gas and oil production at Fidelity for a period up to 36 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

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

The Company's swap and collar agreements are reflected at fair value, based upon futures prices, volatility and time to maturity, among other things.

Asset retirement obligations

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

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Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were \$37.4 million and \$64,000 at December 31, 2009 and 2008, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were \$982,000 and \$51.7 million at December 31, 2009 and 2008, respectively, which is included in prepayments and other current assets.

Insurance

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

Income taxes

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

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

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

Foreign currency translation adjustment

The functional currency of the Company's investment in the Brazilian Transmission Lines, as further discussed in Note 4, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using weighted average daily exchange rates. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

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

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock

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by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. In 2008 and 2007, there were no shares excluded from the calculation of diluted earnings per share. Diluted loss per common share for 2009 was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the year. Due to the loss on common stock for 2009, the effect of outstanding stock options, restricted stock grants and performance share awards was excluded from the computation of diluted loss per common share as their effect was antidilutive. Common stock outstanding includes issued shares less shares held in treasury.

Use of estimates

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

Cash flow information

Cash expenditures for interest and income taxes were as follows:

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

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

New accounting standards

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

Fair Value Measurements and Disclosures In September 2006, the FASB established guidance that defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The guidance applies under other accounting pronouncements that require or permit fair value measurements with certain exceptions and was effective for the Company on January 1, 2008. In February 2008, this guidance was revised to delay the effective date for certain nonfinancial assets and nonfinancial liabilities to January 1, 2009. The types of assets and liabilities that are recognized at fair value effective January 1, 2009, due to the delayed effective date, include nonfinancial assets and nonfinancial liabilities initially measured at fair value in a business combination or new basis event, certain fair value measurements associated with goodwill impairment testing, indefinite-lived intangible assets and nonfinancial

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long-lived assets measured at fair value for impairment assessment, and asset retirement obligations initially measured at fair value. The adoption of the fair value measurements and disclosure guidance, including the application to certain nonfinancial assets and nonfinancial liabilities with a delayed effective date of January 1, 2009, did not have a material effect on the Company's financial position or results of operations.

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

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

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

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

Modernization of Oil and Gas Reporting In January 2009, the SEC adopted final rules amending its oil and gas reporting requirements. The new rules include changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves and permitting disclosure of probable and possible reserves. The final rules were effective on December 31, 2009. For information on the impacts of adopting the SEC's final rules for oil and gas reporting, see Supplementary Financial Information in the 2009 MDU Resources Group, Inc. Form 10-K.

Financial Instruments In April 2009, the FASB issued guidance that requires disclosures about the fair value of financial instruments for interim reporting periods of publicly

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traded companies as well as in annual financial statements, which was effective for the Company in the second quarter of 2009. The adoption of the financial instruments guidance required additional disclosures regarding the Company's fair value of financial instruments; however, it did not impact the Company's financial position or results of operations.

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

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

Oil and Gas Reserve Estimation and Disclosure In January 2010, the FASB issued guidance related to oil and gas reserve estimation and disclosure requirements, which aligned the current oil and gas reserve estimation and disclosures with those of the SEC's final rule, Modernization of Oil and Gas Reporting, and requires disclosure in the first annual period of the estimated effect of the initial application of the guidance. The guidance related to oil and gas reserve estimation and disclosure was effective for the Company on December 31, 2009. For more information on the effects of adopting the oil and gas reserve estimation and disclosure guidance, see Supplementary Financial Information in the 2009 MDU Resources Group, Inc. Form 10-K.

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

Comprehensive income (loss)

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

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

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

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

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

Note 2 - Acquisitions

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

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

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

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

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

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

Note 3 – Discontinued Operations

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

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

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

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

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depletion and amortization expense was recorded from the time each of the assets was classified as held for sale.

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

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

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

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

Revenues at the former independent power production operations were recognized based on electricity delivered and capacity provided, pursuant to contractual commitments and, where applicable, revenues were recognized ratably over the terms of the related contract. Arrangements with multiple revenue-generating activities were recognized with the multiple deliverables divided into separate units of accounting based on specific criteria and revenues of the arrangements allocated to the separate units based on their relative fair values.

Note 4 – Equity Method Investments

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2009 and 2008, include the Brazilian Transmission Lines.

In August 2006, MDU Brasil acquired ownership interests in companies owning the Brazilian Transmission Lines. The interests involve the ENTE (13.3-percent ownership interest), ERTE (13.3-percent ownership interest) and ECTE (25-percent ownership interest) electric transmission lines, which are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments and have between 21 and 23 years remaining under the contracts. Alusa and CEMIG hold the remaining ownership interests, with CELESC also having an ownership interest in ECTE. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

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

In September 2004, Centennial Resources, through indirect wholly owned subsidiaries,

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

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

Note 5 - Goodwill and Other Intangible Assets

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

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

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

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

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

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

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Other amortizable intangible assets at December 31 were as follows:

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

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

Note 6 – Regulatory Assets and Liabilities

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

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

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

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

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

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

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

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The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. In 2009, the Company determined that plant removal costs related to recent acquisitions should be reclassified from accumulated depreciation to a regulatory liability. This reclassification is reflected in the preceding table.

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

Note 7 - Derivative Instruments

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

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2009, the Company had no outstanding foreign currency or interest rate hedges.

Cascade and Intermountain

At December 31, 2009, Cascade and Intermountain held natural gas swap agreements, with total forward notional volumes of 12.1 million MMBtu, which were not designated as hedges. Cascade and Intermountain utilize natural gas swap agreements to manage a portion of their regulated natural gas supply portfolios in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the IPUC, WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Cascade and Intermountain record periodic changes in the fair market value of the derivative instruments on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements

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of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade and Intermountain will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the year ended December 31, 2009, Cascade and Intermountain recorded the decrease in the fair market value of the derivative instruments of \$61.9 million in regulatory assets.

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

Fidelity

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

The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). At the date the natural gas and oil quantities are settled, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings. The proceeds received for natural gas and oil production are generally based on market prices.

For the years ended December 31, 2009, 2008 and 2007, the amount of hedge ineffectiveness was immaterial, and there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges.

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

As of December 31, 2009, the maximum term of the swap and collar agreements, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 24 months. The Company estimates that over the next 12 months net losses of approximately \$3.8 million (after tax) will be reclassified from accumulated other

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comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Certain of Fidelity's derivative instruments contain cross-default provisions that state if Fidelity fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2009, was \$13.9 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2009, was \$13.9 million.

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

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

Note 8 - Fair Value Measurements

On January 1, 2008, the Company elected to measure its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. These investments had previously been accounted for as available-for-sale investments. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled \$34.8 million and \$27.7 million as of December 31, 2009 and 2008, respectively, are classified as Investments on the Consolidated Balance Sheets. The increase in the fair value of these investments for the year ended December 31, 2009, was \$7.1 million (before tax). The decrease in the fair value of these investments for the year ended December 31, 2008, was \$8.6 million (before tax). The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income. The Company did not elect the fair value option for its remaining available-for-sale securities, which are auction rate securities. The Company's auction rate securities, which totaled \$11.4 million at December 31, 2009 and 2008, are

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accounted for as available-for-sale and are recorded at fair value. The fair value of the auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments.

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

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

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Fair Value Measurements at
December 31, 2008, Using

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Collateral Provided to Counterparties	Balance at December 31, 2008
<i>(In thousands)</i>					
Assets:					
Available-for-sale securities	\$27,725	\$ 11,400	\$ —	\$ —	\$ 39,125
Commodity derivative instruments - current	—	78,164	—	—	78,164
Commodity derivative instruments - noncurrent	—	3,222	—	—	3,222
Total assets measured at fair value	\$27,725	\$ 92,786	\$ —	\$ —	\$120,511
Liabilities:					
Commodity derivative instruments - current	\$ —	\$ 67,629	\$ —	\$ 11,100	\$ 56,529
Commodity derivative instruments - noncurrent	—	23,534	—	—	23,534
Total liabilities measured at fair value	\$ —	\$ 91,163	\$ —	\$ 11,100	\$ 80,063

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

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The estimated fair value of the Company's long-term debt was based on quoted market prices of the same or similar issues. The estimated fair value of the Company's long-term debt at December 31 was as follows:

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

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

Note 9 - Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in

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compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2009. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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

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

(a) The \$125 million commercial paper program is supported by a revolving credit agreement with various banks totaling \$125 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of \$150 million). There were no amounts outstanding under the credit agreement.

(b) Amount outstanding under commercial paper program.

(c) Or such time as the agreement is terminated by either of the parties thereto.

(d) Certain provisions allow for increased borrowings, up to a maximum of \$75 million.

(e) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.

(f) Provisions allow for an extension of up to two years upon consent of the banks.

(g) Certain provisions allow for increased borrowings, up to a maximum of \$70 million.

(h) The \$400 million commercial paper program is supported by a revolving credit agreement with various banks totaling \$400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of \$450 million). There were no amounts outstanding under the credit agreement.

(i) Certain provisions allow for an extension to December 23, 2011.

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

The following includes information related to the preceding table.

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Short-term borrowings

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

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

Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Intermountain Gas Company The weighted average interest rate for borrowings outstanding under the credit agreement at December 31, 2009, was 3.25 percent. The credit agreement contains customary covenants and provisions, including covenants of Intermountain not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent, or (B) the ratio of Intermountain's earnings before interest, taxes, depreciation and amortization to interest expense (determined on a consolidated basis), for the 12-month period ended each fiscal quarter, to be less than 2 to 1. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (i) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of \$5 million, (ii) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (iii) certain conditions result in an early termination date under any swap contract, then Intermountain shall be in default under the revolving credit agreement.

Long-term debt

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

The Company's credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company alone, excluding its subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. Other covenants include restrictions on the sale of certain assets and on the making of certain investments.

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

In November 2009, the Company completed a defeasance of its outstanding 8.60% Secured Medium-Term Notes, Series A, due April 1, 2012 (8.60% Notes), by depositing approximately

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\$5.5 million with the Mortgage trustee. The \$5.5 million deposit will be used solely to satisfy the principal and remaining interest obligations on the 8.60% Notes. These securities are the only remaining first mortgage bonds outstanding under the Mortgage, other than \$30.0 million of first mortgage bonds which were held by the Indenture trustee for the benefit of the senior note holders. In connection with the defeasance of the 8.60% Notes, the Mortgage was discharged and the lien of the Indenture was discharged so that the Company's 5.98% Senior Notes due 2033 are now unsecured.

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

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

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

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

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

Williston Basin Interstate Pipeline Company The uncommitted long-term private shelf agreement contains customary covenants and provisions, including a covenant of Williston Basin not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments.

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

	2009	2008
	<i>(In thousands)</i>	
First mortgage bonds and notes:		
Secured Medium-Term Notes, Series A, 8.60%	\$ —	\$ 5,500
Senior Notes, 5.98%, due December 15, 2033	—	30,000 (a)
Total first mortgage bonds and notes	—	35,500
Senior Notes at a weighted average rate of 6.07%, due on dates ranging from October 30, 2010 to March 8, 2037	1,370,455	1,271,227
Commercial paper supported by revolving credit agreements	—	172,500
Medium-Term Notes at a weighted average rate of 7.72%, due on dates ranging from September 4, 2012 to March 16, 2029	81,000	81,000
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	42,070	42,971
Credit agreements at a weighted average rate of 5.67%, due on dates ranging from April 1, 2010 to November 30, 2038	5,781	44,205
Discount	—	(101)
Total long-term debt	1,499,306	1,647,302
Less current maturities	12,629	78,666
Net long-term debt	\$ 1,486,677	\$ 1,568,636
<i>(a) The \$30.0 million of 5.98% Senior Notes became unsecured upon the defeasance of the outstanding 8.60% Notes, as previously discussed.</i>		

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

Note 10 - Asset Retirement Obligations

The Company records obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution and transmission facilities and buildings, and certain other obligations associated with leased properties.

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

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

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

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2009 and 2008, was \$5.9 million.

Note 11 - Preferred Stocks

Preferred stocks at December 31 were as follows:

	2009	2008
	<i>(Dollars in thousands)</i>	
Authorized:		
Preferred -		
500,000 shares, cumulative, par value \$100, issuable in series		
Preferred stock A -		
1,000,000 shares, cumulative, without par value, issuable in series		
(none outstanding)		
Preference -		
500,000 shares, cumulative, without par value, issuable in series		
(none outstanding)		
Outstanding		
4.50% Series - 100,000 shares	\$10,000	\$10,000
4.70% Series - 50,000 shares	5,000	5,000
Total preferred stocks	\$15,000	\$15,000

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

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

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

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

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Note 12 - Common Stock

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From January 2007 through March 2007 and October 1, 2008 through October 21, 2008, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From April 2007 through September 30, 2008, and October 22, 2008 through December 2009, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2009, there were 23.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by state laws, applicable regulatory limitations, and compliance with the requirements of the Company's credit agreements. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 - Stock-Based Compensation

The Company has several stock-based compensation plans and is authorized to grant options, restricted stock and stock for up to 16.9 million shares of common stock and has granted options, restricted stock and stock of 7.3 million shares through December 31, 2009. The Company generally issues new shares of common stock to satisfy stock option exercises, restricted stock, stock and performance share awards.

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

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

Stock options

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

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

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

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

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

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

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

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

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

Restricted stock awards

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

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

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

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 49,649 shares with a fair value of \$879,000, 45,675 shares with a fair value of \$1.2 million and 48,228 shares with a fair value of \$1.5 million issued under this plan during the years ended December 31, 2009, 2008 and 2007, respectively.

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Performance share awards

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

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

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

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value. The grant-date fair value of performance share awards granted during the years ended December 31, 2009, 2008 and 2007, was \$20.39, \$30.71 and \$23.55, per share, respectively. The grant-date fair value for the performance shares was determined by Monte Carlo simulation using a blended volatility term structure in the range of 40.40 percent to 50.98 percent in 2009, 21.54 percent to 22.97 percent in 2008 and 18.17 percent to 18.73 percent in 2007 comprised of 50 percent historical volatility and 50 percent implied volatility and a risk-free interest rate term structure in the range of .30 percent to 1.36 percent in 2009, 1.87 percent to 2.23 percent in 2008 and 4.75 percent to 5.21 percent in 2007 based on U.S. Treasury security rates in effect as of the grant date. In addition, the mean over all simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was \$1.79, \$1.64 and \$1.25 per target share for the 2009, 2008 and 2007 awards, respectively. The fair value of performance share awards that vested during the years ended December 31, 2009, 2008 and 2007, was \$2.8 million, \$8.5 million and \$6.0 million, respectively.

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

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

Note 14 - Income Taxes

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

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

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

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

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

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

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

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

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

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

Years ended December 31,	2009		2008		2007	
	Amount	%	Amount	%	Amount	%
(Dollars in thousands)						
Computed tax at federal statutory rate	\$ (76,778)	35.0	\$ 154,402	35.0	\$ 179,484	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	(7,280)	3.3	10,709	2.4	17,121	3.3
Deductible K-Plan dividends	(2,369)	1.1	(2,144)	(.5)	(2,134)	(.4)
Depletion allowance	(2,320)	1.0	(2,932)	(.7)	(4,073)	(.8)
Federal renewable energy credit	(1,452)	.7	(1,235)	(.3)	—	—
Foreign operations	(1,148)	.5	423	.1	9,603	1.8
Domestic production activities deduction	(856)	.4	(3,031)	(.7)	(4,787)	(.9)
Resolution of tax matters and uncertain tax positions	881	(.4)	595	.1	208	—
Other	(4,770)	2.2	(9,311)	(2.0)	(5,398)	(.9)
Total income tax expense (benefit)	\$ (96,092)	43.8	\$ 147,476	33.4	\$ 190,024	37.1

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

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

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million at December 31, 2009. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2009, was approximately \$10.5 million, which was largely recognized in 2007. Future earnings will also be subject to additional U.S. taxes, net of allowable foreign tax credits.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2004.

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

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

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

Included in the balance of unrecognized tax benefits at December 31, 2009, were \$540,000 of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2009, was \$6.4 million, including approximately \$804,000 for the payment of interest and penalties.

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

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

Note 15 - Business Segment Data

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

The electric segment generates, transmits and distributes electricity in Montana, North

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

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

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

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

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

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

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

	2009	2008	2007
	<i>(In thousands)</i>		
External operating revenues:			
Electric	\$ 196,171	\$ 208,326	\$ 193,367
Natural gas distribution	1,072,776	1,036,109	532,997
Pipeline and energy services	235,322	440,764	369,345
	1,504,269	1,685,199	1,095,709
Construction services	818,685	1,256,759	1,102,566
Natural gas and oil production	338,425	420,637	288,148
Construction materials and contracting	1,515,122	1,640,683	1,761,473
Other	—	—	—
	2,672,232	3,318,079	3,152,187
Total external operating revenues	\$ 4,176,501	\$ 5,003,278	\$ 4,247,896
Intersegment operating revenues:			
Electric	\$ —	\$ —	\$ —
Natural gas distribution	—	—	—
Construction services	379	560	649
Pipeline and energy services	72,505	91,389	77,718
Natural gas and oil production	101,230	291,642	226,706
Construction materials and contracting	—	—	—
Other	9,487	10,501	10,061
Intersegment eliminations	(183,601)	(394,092)	(315,134)
Total intersegment operating revenues	\$ —	\$ —	\$ —
Depreciation, depletion and amortization:			
Electric	\$ 24,637	\$ 24,030	\$ 22,549
Natural gas distribution	42,723	32,566	19,054
Construction services	12,760	13,398	14,314
Pipeline and energy services	25,581	23,654	21,631
Natural gas and oil production	129,922	170,236	127,408
Construction materials and contracting	93,615	100,853	95,732
Other	1,304	1,283	1,244
Total depreciation, depletion and amortization	\$ 330,542	\$ 366,020	\$ 301,932
Interest expense:			
Electric	\$ 9,577	\$ 8,674	\$ 6,737
Natural gas distribution	30,656	24,004	13,566
Construction services	4,490	4,893	4,878
Pipeline and energy services	8,896	8,314	8,769
Natural gas and oil production	10,621	12,428	8,394
Construction materials and contracting	20,495	24,291	23,997
Other	43	374	10,717
Intersegment eliminations	(679)	(1,451)	(4,821)
Total interest expense	\$ 84,099	\$ 81,527	\$ 72,237

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	2009	2008 (In thousands)	2007
Income taxes:			
Electric	\$ 8,205	\$ 8,225	\$ 8,528
Natural gas distribution	16,331	18,827	6,477
Construction services	15,189	26,952	26,829
Pipeline and energy services	22,982	15,427	18,524
Natural gas and oil production	(187,000)	68,701	78,348
Construction materials and contracting	25,940	8,947	39,045
Other	2,261	397	12,273
Total income taxes	\$ (96,092)	\$ 147,476	\$ 190,024
Earnings (loss) on common stock:			
Electric	\$ 24,099	\$ 18,755	\$ 17,700
Natural gas distribution	30,796	34,774	14,044
Construction services	25,589	49,782	43,843
Pipeline and energy services	37,845	26,367	31,408
Natural gas and oil production	(296,730)	122,326	142,485
Construction materials and contracting	47,085	30,172	77,001
Other	7,357	10,812	(4,380)
Earnings (loss) on common stock before income from discontinued operations	(123,959)	292,988	322,101
Income from discontinued operations, net of tax	—	—	109,334
Total earnings (loss) on common stock	\$ (123,959)	\$ 292,988	\$ 431,435
Capital expenditures:			
Electric	\$ 115,240	\$ 72,989	\$ 91,548
Natural gas distribution	43,820	398,116	500,178
Construction services	12,814	24,506	18,241
Pipeline and energy services	70,168	42,960	39,162
Natural gas and oil production	183,140	710,742	283,589
Construction materials and contracting	26,313	127,578	189,727
Other	3,196	774	1,621
Net proceeds from sale or disposition of property	(26,679)	(86,927)	(24,983)
Net capital expenditures before discontinued operations	428,012	1,290,738	1,099,083
Discontinued operations	—	—	(548,216)
Total net capital expenditures	\$ 428,012	\$ 1,290,738	\$ 550,867
Assets:			
Electric*	\$ 569,666	\$ 479,639	\$ 428,200
Natural gas distribution*	1,588,144	1,548,005	942,454
Construction services	328,895	476,092	456,564
Pipeline and energy services	538,230	506,872	500,755
Natural gas and oil production	1,137,628	1,792,792	1,299,406
Construction materials and contracting	1,449,469	1,552,296	1,642,729
Other**	378,920	232,149	322,326
Total assets	\$ 5,990,952	\$ 6,587,845	\$ 5,592,434

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	2009	2008 (In thousands)	2007
Property, plant and equipment:			
Electric*	\$ 941,791	\$ 848,725	\$ 784,705
Natural gas distribution*	1,456,208	1,429,487	948,446
Construction services	116,236	111,301	101,935
Pipeline and energy services	675,199	640,921	600,712
Natural gas and oil production	2,028,794	2,477,402	1,923,899
Construction materials and contracting	1,514,989	1,524,029	1,538,716
Other	33,365	30,372	31,833
Less accumulated depreciation, depletion and amortization	2,872,465	2,761,319	2,270,691
Net property, plant and equipment	\$ 3,894,117	\$ 4,300,918	\$ 3,659,555

* Includes allocations of common utility property.

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

Note: The results reflect a \$620.0 million (\$384.4 million after tax) and \$135.8 million (\$84.2 million after tax) noncash write-down of natural gas and oil properties in 2009 and 2008, respectively.

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

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

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

Note 16 - Employee Benefit Plans

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

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

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

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

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

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

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

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

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

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

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

	Pension Benefits			Other Postretirement Benefits		
	2009	2008	2007	2009	2008	2007
	<i>(In thousands)</i>					
Components of net periodic benefit cost:						
Service cost	\$ 8,127	\$ 8,812	\$ 9,098	\$ 2,206	\$ 1,977	\$ 1,865
Interest cost	21,919	21,264	18,591	5,465	5,079	4,212
Expected return on assets	(25,062)	(26,501)	(22,524)	(5,471)	(5,657)	(4,776)
Amortization of prior service cost (credit)	605	665	756	(2,756)	(2,755)	(1,300)
Recognized net actuarial loss	2,096	1,050	1,605	970	594	73
Curtailment loss	1,650	—	—	—	—	—
Amortization of net transition obligation	—	—	—	2,125	2,125	2,125
Net periodic benefit cost, including amount capitalized	9,335	5,290	7,526	2,539	1,363	2,199
Less amount capitalized	1,127	642	991	330	307	373
Net periodic benefit cost	8,208	4,648	6,535	2,209	1,056	1,826
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	(29,000)	102,125	(11,095)	(2,314)	26,478	1,507
Acquisition-related actuarial loss	—	—	12,291	—	—	9,818
Prior service credit	—	—	—	(9,321)	(382)	—
Acquisition-related prior service credit	—	—	(1,842)	—	—	(12,472)
Amortization of actuarial loss	(2,096)	(1,050)	(1,605)	(970)	(594)	(73)
Amortization of prior service (cost) credit	(2,255)	(665)	(756)	2,756	2,755	1,300
Amortization of net transition obligation	—	—	—	(2,125)	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	(33,351)	100,410	(3,007)	(11,974)	26,132	(2,045)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	\$ (25,143)	\$105,058	\$ 3,528	\$ (9,765)	\$27,188	\$ (219)

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

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

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
Discount rate	5.75%	6.25%	5.75%	6.25%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%

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

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

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

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

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

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2009:

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

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

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

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

	Fair Value Measurements at December 31, 2009, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2009
	(In thousands)			
Assets:				
Common stocks (a)	\$ 133,989	\$ —	\$ —	\$ 133,989
Collective and mutual funds (b)	39,234	10,379	—	49,613
U.S. government and U.S. government-sponsored securities (c)	—	28,091	—	28,091
Corporate and municipal bonds (d)	—	27,968	—	27,968
Collateral held on loaned securities (e)	—	21,597	937	22,534
Cash and cash equivalents	17,958	—	—	17,958
Total assets measured at fair value	191,181	88,035	937	280,153
Liabilities:				
Obligation for collateral received	24,826	—	—	24,826
Net assets measured at fair value	\$ 166,355	\$ 88,035	\$ 937	\$ 255,327

- (a) This category includes approximately 75 percent U.S. common stocks and 25 percent non-U.S. common stocks.
- (b) Collective and mutual funds invest approximately 43 percent in common stock of large-cap U.S. companies, 21 percent in asset-backed securities, 17 percent in cash and cash equivalents, 8 percent in small-cap U.S. companies and 11 percent in other investments.
- (c) This category includes approximately 69 percent U.S. government-sponsored securities (asset-backed securities) and 31 percent U.S. government securities.
- (d) This category includes approximately 78 percent corporate bonds and 22 percent municipal bonds.
- (e) This category includes collateral held at December 31, 2009, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, money market funds, corporate bonds, commercial paper, asset-backed securities and certificates of deposit.

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

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

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

Fair Value Measurements at December 31, 2009, Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2009
	(In thousands)			
Assets:				
Money market funds	\$ 1,469	\$ —	\$ —	\$ 1,469
Common stock	2,897	—	—	2,897
Insurance investment contract*	—	62,618	—	62,618
Total assets measured at fair value	\$ 4,366	\$ 62,618	\$ —	\$ 66,984

* Invested in mutual funds.

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

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

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

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

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

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of \$67.9 million at December 31, 2009, consisting of equity securities of \$32.1 million, life insurance carried on plan participants (payable upon the employee's death) of \$29.8 million, fixed-income securities of \$2.7 million and other investments of \$3.3 million, which the Company anticipates using to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was \$8.8 million, \$9.0 million and \$7.6 million in 2009, 2008 and 2007, respectively. The total projected benefit obligation for these plans was \$93.0 million and \$87.2 million at December 31, 2009 and 2008, respectively. The accumulated benefit obligation for these plans was \$84.8 million and \$77.3 million at December 31, 2009 and 2008, respectively. A discount rate of 5.75 percent and 6.25 percent at December 31, 2009 and 2008, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2009 and 2008, were used to determine benefit obligations. A discount rate of 6.25 percent and 6.00 percent at December 31, 2009 and 2008, respectively, and a rate of compensation increase of 4.00 percent and 4.25 percent at December 31, 2009 and 2008, respectively, were used to determine net periodic benefit cost.

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

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

Note 17 - Jointly Owned Facilities

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

The Company's share of the Big Stone Station and Coyote Station operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

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

Note 18 - Regulatory Matters and Revenues Subject to Refund

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

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

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. There had been one remaining issue outstanding related to this rate change application regarding certain service restrictions. After various steps in this proceeding, including a Williston Basin Request for Rehearing, an appeal to the D.C. Appeals Court, and a remand to FERC, the FERC, on October 30, 2009, issued its Order on

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Remand in which it upheld its previous decision. No party requested rehearing of the order, which is now final, and no issue is outstanding in this application.

Note 19 - Commitments and Contingencies

Litigation

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

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

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

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

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

Electric Operations In June 2008, the Sierra Club filed a complaint in the South Dakota Federal District Court against Montana-Dakota and the two other co-owners of the Big Stone Station. The complaint alleged certain violations of the PSD and NSPS provisions of the Clean Air Act and certain violation of the South Dakota SIP. The action further alleged

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

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

Environmental matters

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

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, MBI does not believe it is a Responsible Party. In

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NOTES TO FINANCIAL STATEMENTS (Continued)			

addition, MBI has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. MBI has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter of March 2, 2009, LWG stated its intent to file suit against MBI and others to recover LWG's investigation costs to the extent MBI cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, MBI has agreed to participate in the alternative dispute resolution process.

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

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

The first claim is for soil and groundwater contamination at a site in Oregon and was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately \$500,000 to \$11.0 million. An ecological risk assessment draft report was submitted to the Oregon DEQ in June 2009. The assessment showed no unacceptable risk to the aquatic ecological receptors present in the shoreline along the site and concluded that no further ecological investigation is necessary. The report is being reviewed by the Oregon DEQ. It is anticipated the Oregon DEQ will recommend a cleanup alternative for the site after it completes its review of the report. It is not known at this time what share of the cleanup costs will actually be borne by Cascade.

The second claim is for contamination at a site in Washington and was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from \$340,000 to \$6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. There is currently not enough information to estimate the potential liability to Cascade associated with this claim.

The third claim is also for contamination at a site in Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade's predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed \$8.0 million. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim.

To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2009, were \$25.2 million in 2010, \$20.3 million in 2011, \$15.3 million in

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

Purchase commitments

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

Guarantees

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

Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent Power LLC, which provided a \$10 million bank letter of credit to Centennial in support of the guarantee obligation. On February 27, 2009, Centennial received a Notice and Demand from LPP under the guaranty agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. On December 4, 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand seeks compensatory damages of \$146 million plus damages for increased operating, capital and construction costs related to a water treatment facility for the generating facility. LPP's notice of demand for arbitration also demanded performance of the guarantee by Centennial. The Company believes the indemnification claims against Centennial are without merit and intends to vigorously defend against such claims.

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

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas swap and collar agreements as the amount of the obligation is dependent upon natural gas commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas swap and collar agreements at December 31, 2009, expire in 2010 and 2011; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. There were no amounts outstanding by Fidelity at December 31, 2009. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

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Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts, a conditional purchase agreement and certain other guarantees. At December 31, 2009, the fixed maximum amounts guaranteed under these agreements aggregated \$234.4 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate \$65.3 million in 2010; \$141.8 million in 2011; \$16.7 million in 2012; \$1.8 million in 2013; \$200,000 in 2014; \$1.0 million in 2018; \$300,000 in 2019; \$3.3 million, which is subject to expiration on a specified number of days after the receipt of written notice; and \$4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was \$570,000 and was reflected on the Consolidated Balance Sheet at December 31, 2009. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

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

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

In addition, Centennial and Knife River have issued guarantees to third parties related to the Company's routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation in relation to the purchase of certain maintenance items, materials or lease obligations, Centennial or Knife River would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items and materials were reflected on the Consolidated Balance Sheet at December 31, 2009.

In the normal course of business, Centennial has purchased surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2009, approximately \$532 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Note 20 - Subsequent Events

The Company evaluated events or transactions between the balance sheet date and April 7, 2010, the date the financial statements were available for issuance, which would require recognition or disclosure in the financial statements.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1				
2	Intangible Plant			
3				
4	301 Organization			
5	302 Franchises & Consents			
6	303 Miscellaneous Intangible Plant	\$4,372,226	\$4,667,865	6.76%
7				
8	TOTAL Intangible Plant	\$4,372,226	\$4,667,865	6.76%
9				
10	Production Plant			
11				
12	Steam Production			
13				
14	310 Land & Land Rights	\$255,125	\$256,951	0.72%
15	311 Structures & Improvements	12,409,159	12,801,999	3.17%
16	312 Boiler Plant Equipment	40,116,492	41,575,388	3.64%
17	313 Engines & Engine Driven Generators			
18	314 Turbogenerator Units	11,277,231	11,794,485	4.59%
19	315 Accessory Electric Equipment	3,709,541	3,763,820	1.46%
20	316 Miscellaneous Power Plant Equipment	3,928,160	4,016,611	2.25%
21				
22	TOTAL Steam Production Plant	\$71,695,708	\$74,209,254	3.51%
23				
24	Nuclear Production			
25				
26	320 Land & Land Rights			
27	321 Structures & Improvements			
28	322 Reactor Plant Equipment			
29	323 Turbogenerator Units			
30	324 Accessory Electric Equipment			
31	325 Miscellaneous Power Plant Equipment			
32				
33	TOTAL Nuclear Production Plant		NOT APPLICABLE	
34				
35	Hydraulic Production			
36				
37	330 Land & Land Rights			
38	331 Structures & Improvements			
39	332 Reservoirs, Dams & Waterways			
40	333 Water Wheels, Turbines & Generators			
41	334 Accessory Electric Equipment			
42	335 Miscellaneous Power Plant Equipment			
43	336 Roads, Railroads & Bridges			
44				
45	TOTAL Hydraulic Production Plant		NOT APPLICABLE	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1				
2	Production Plant (cont.)			
3				
4	Other Production			
5				
6	340 Land & Land Rights	\$16,663	\$16,782	0.71%
7	341 Structures & Improvements	196,918	202,022	2.59%
8	342 Fuel Holders, Producers & Accessories	153,984	627,686	307.63%
9	343 Prime Movers			
10	344 Generators	16,482,089	20,302,431	23.18%
11	345 Accessory Electric Equipment	232,135	253,396	9.16%
12	346 Miscellaneous Power Plant Equipment	13,889	33,554	141.59%
13				
14	TOTAL Other Production Plant	\$17,095,678	\$21,435,871	25.39%
15				
16	TOTAL Production Plant	\$88,791,386	\$95,645,125	7.72%
17				
18	Transmission Plant			
19				
20	350 Land & Land Rights	\$684,646	\$688,795	0.61%
21	352 Structures & Improvements	448	451	0.67%
22	353 Station Equipment	17,337,267	18,926,972	9.17%
23	354 Towers & Fixtures	1,198,577	1,194,315	-0.36%
24	355 Poles & Fixtures	7,086,950	7,082,007	-0.07%
25	356 Overhead Conductors & Devices	5,949,337	5,946,296	-0.05%
26	357 Underground Conduit	312,249	296,583	-5.02%
27	358 Underground Conductors & Devices	645,375	582,385	-9.76%
28	359 Roads & Trails			
29				
30	TOTAL Transmission Plant	\$33,214,849	\$34,717,804	4.52%
31				
32	Distribution Plant			
33				
34	360 Land & Land Rights	\$265,747	\$266,555	0.30%
35	361 Structures & Improvements			
36	362 Station Equipment	5,883,351	6,418,608	9.10%
37	363 Storage Battery Equipment			
38	364 Poles, Towers & Fixtures	6,317,717	6,555,859	3.77%
39	365 Overhead Conductors & Devices	4,921,857	5,004,648	1.68%
40	366 Underground Conduit	12,967	12,967	0.00%
41	367 Underground Conductors & Devices	6,138,549	6,559,017	6.85%
42	368 Line Transformers	8,398,019	8,699,997	3.60%
43	369 Services	4,142,870	4,270,032	3.07%
44	370 Meters	2,814,544	2,838,192	0.84%
45	371 Installations on Customers' Premises	728,468	735,888	1.02%
46	372 Leased Property on Customers' Premises			
47	373 Street Lighting & Signal Systems	1,641,533	1,674,737	2.02%
48				
49	TOTAL Distribution Plant	\$41,265,622	\$43,036,500	4.29%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1				
2	General Plant			
3				
4	389 Land & Land Rights	\$2,065	\$2,066	0.05%
5	390 Structures & Improvements	121,025	121,060	0.03%
6	391 Office Furniture & Equipment	206,032	203,241	-1.35%
7	392 Transportation Equipment	1,193,427	1,171,433	-1.84%
8	393 Stores Equipment	7,904	7,904	0.00%
9	394 Tools, Shop & Garage Equipment	463,382	481,608	3.93%
10	395 Laboratory Equipment	210,977	211,039	0.03%
11	396 Power Operated Equipment	2,449,842	2,164,233	-11.66%
12	397 Communication Equipment	331,939	364,091	9.69%
13	398 Miscellaneous Equipment	19,855	7,749	-60.97%
14	399 Other Tangible Property			
15				
16	TOTAL General Plant	\$5,006,448	\$4,734,424	-5.43%
17				
18	Common Plant			
19				
20	389 Land & Land Rights	\$201,319	\$201,139	-0.09%
21	390 Structures & Improvements	3,376,502	3,444,359	2.01%
22	391 Office Furniture & Equipment	897,762	917,445	2.19%
23	392 Transportation Equipment	1,254,750	1,081,207	-13.83%
24	393 Stores Equipment	11,180	13,095	17.13%
25	394 Tools, Shop & Garage Equipment	206,247	226,692	9.91%
26	395 Laboratory Equipment			
27	396 Power Operated Equipment	526	11,856	2153.99%
28	397 Communication Equipment	305,014	427,210	40.06%
29	398 Miscellaneous Equipment	112,454	115,949	3.11%
30	399 Other Tangible Property			
31				
32	TOTAL Common Plant	\$6,365,754	\$6,438,952	1.15%
33				
34				
35	TOTAL Electric Plant in Service	\$179,016,285	\$189,240,670	5.71%

MONTANA DEPRECIATION SUMMARY

Year: 2009

	Functional Plant Classification	Plant Cost	Accumulated Depreciation		Current Avg. Rate
			Last Year Bal.	This Year Bal.	
1					
2	Steam Production 1/	\$77,980,493	\$58,818,491	\$60,598,019	3.17%
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production	21,435,871	3,231,501	3,930,158	3.17%
6	Transmission	34,717,804	17,825,555	18,360,920	1.68%
7	Distribution	43,036,500	22,358,116	23,183,932	2.80%
8	General	6,191,267	3,432,689	3,451,855	3.19%
9	Common	9,649,974	5,181,577	5,605,654	4.66%
10	TOTAL	\$193,011,909	\$110,847,929	\$115,130,538	2.89%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	\$1,158,049	\$1,315,422	13.59%
3	152 Fuel Stock Expenses Undistributed			
4	153 Residuals			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)	547,790	586,719	7.11%
9	Transmission Plant (Estimated)	307,284	318,370	3.61%
10	Distribution Plant (Estimated)	763,158	686,414	-10.06%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed			
16				
17	TOTAL Materials & Supplies	\$2,776,281	\$2,906,925	4.71%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent	% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number 2007.7.79			
2	Order Number 6846f			
3				
4	Common Equity	50.67%	10.25%	5.19%
5	Preferred Stock	3.58%	4.61%	0.17%
6	Long Term Debt	38.18%	7.22%	2.76%
7	Short Term Debt	7.57%	6.11%	0.46%
8	TOTAL	100.00%		8.58%
9				
10	<u>Actual at Year End</u>			
11				
12	Common Equity	51.492%	10.250%	5.278%
13	Preferred Stock	2.540%	4.594%	0.117%
14	Long Term Debt	45.662%	6.845%	3.126%
15	Short Term Debt	0.306%	11.590%	0.035%
16	TOTAL	100.000%		8.556%

STATEMENT OF CASH FLOWS

Year: 2009

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	Cash Flows from Operating Activities:			
4	Net Income	\$293,673,229	(\$123,274,095)	-141.98%
5	Depreciation	34,040,420	35,082,590	3.06%
6	Amortization	316,354	(319,003)	-200.84%
7	Deferred Income Taxes - Net	19,761,591	8,387,646	-57.56%
8	Investment Tax Credit Adjustments - Net	(248,195)	(199,265)	19.71%
9	Change in Operating Receivables - Net	3,271,846	(3,724,383)	-213.83%
10	Change in Materials, Supplies & Inventories - Net	8,217,051	(8,443,567)	-202.76%
11	Change in Operating Payables & Accrued Liabilities - Net	(34,470,080)	13,052,368	137.87%
12	Change in Other Regulatory Assets	2,019,006	7,104,393	251.88%
13	Change in Other Regulatory Liabilities	(781,318)	200,390	125.65%
14	Allowance for Other Funds Used During Construction (AFUDC)	(119,056)	(5,557,565)	-4568.03%
15	Change in Other Assets & Liabilities - Net	(13,303,075)	45,568,156	442.54%
16	Less Undistributed Earnings from Subsidiary Companies	(171,164,580)	255,489,860	249.27%
17	Other Operating Activities (explained on attached page)			
18	Net Cash Provided by/(Used in) Operating Activities	\$141,213,193	\$223,367,525	58.18%
19				
20	Cash Inflows/Outflows From Investment Activities:			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	(\$105,520,724)	(\$125,809,740)	-19.23%
23	Acquisition of Other Noncurrent Assets	5,940,589	(6,588,982)	-210.91%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(172,005,700)		100.00%
26	Contributions and Advances from Affiliates	121,000,000	22,915,660	-81.06%
27	Disposition of Investments in and Advances to Affiliates			
28	Other Investing Activities: Depreciation & RWIP on Nonutility Plant	122,650	136,225	11.07%
29	Net Cash Provided by/(Used in) Investing Activities	(\$150,463,185)	(\$109,346,837)	27.33%
30				
31	Cash Flows from Financing Activities:			
32	Proceeds from Issuance of:			
33	Long-Term Debt	\$100,508,867	\$27,493,724	-72.65%
34	Preferred Stock			
35	Common Stock	15,011,178	65,207,454	334.39%
36	Other:	57,000,000	264,363	-99.54%
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper			
39	Payment for Retirement of:			
40	Long-Term Debt	(53,600,000)	(5,600,000)	89.55%
41	Preferred Stock			
42	Common Stock			
43	Other: Adjustment to Retained Earnings	(44,761)	(384,084)	-758.08%
44	Net Decrease in Short-Term Debt			
45	Dividends on Preferred Stock	(685,004)	(685,004)	0.00%
46	Dividends on Common Stock	(109,925,942)	(115,447,274)	-5.02%
47	Other Financing Activities (related to IGC acquisition)		(57,000,000)	
48	Net Cash Provided by (Used in) Financing Activities	\$8,264,338	(\$86,150,821)	-1142.44%
49				
50	Net Increase/(Decrease) in Cash and Cash Equivalents	(\$985,654)	\$27,869,867	2927.55%
51	Cash and Cash Equivalents at Beginning of Year	\$3,219,158	\$2,233,504	-30.62%
52	Cash and Cash Equivalents at End of Year	\$2,233,504	\$30,103,371	1247.81%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 24

LONG TERM DEBT

Year: 2009

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost % 1/
1	6.61% Senior Notes	09/09	09/16	\$25,000,000	\$24,423,218	\$25,000,000	6.61%	\$1,778,500	7.11%
2	6.66% Senior Notes	10/09	09/16	25,000,000	24,423,218	25,000,000	6.66%	1,791,500	7.17%
3	5.98% Senior Notes	12/03	12/33	30,000,000	29,456,832	30,000,000	5.98%	1,861,500	6.21%
4	6.33 % Senior Notes	08/06	08/26	100,000,000	89,123,930	100,000,000	6.33%	7,514,000	7.51%
5	6.04 % Senior Notes	09/08	09/18	100,000,000	99,637,568	100,000,000	6.04%	6,181,000	6.18%
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24									
25									
26	TOTAL			\$280,000,000	\$267,064,766	\$280,000,000		\$19,126,500	6.83%

1/ Includes interest expense, bond discount expense, debt issuance expense and loss on bond reacquisition and redemption.

PREFERRED STOCK

Year: 2009

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price 1/	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	4.50 % Cumulative	01/51	100,000	\$100	\$105	\$10,000,000	4.50%	\$10,000,000	\$450,000	4.50%
2	4.70 % Cumulative	12/55	50,000	100	102	5,000,000	4.70%	5,000,000	235,000	4.70%
3	5.10 % Cumulative 2/	05/61	50,000	100	102	4,947,548	5.29%	600,000	36,995	5.29%
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5										
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28										
29										
30										
31										
32	TOTAL					\$19,947,548		\$15,600,000	\$721,995	4.63%

1/ Plus accrued dividends.

2/ Mandatory annual redemption of \$100,000.

Year: 2009

COMMON STOCK

		Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share 2/	Dividends Per Share	Retention Ratio	Market Price High	Low	Price/ Earnings Ratio 3/
1	January								
2	February								
3	March	181,743,059	\$12.97	(\$1.87)	\$0.1550	108.29%	\$22.89	\$12.79	N/A
4	April								
5	May								
6	June	183,963,530	13.02	0.30	0.1550	48.33%	19.76	15.70	N/A
7	July								
8	August								
9	September	185,161,819	13.37	0.50	0.1550	69.00%	21.16	17.44	N/A
10	October								
11	November								
12	December	187,747,560	13.61	0.39	0.1575	59.62%	24.22	19.96	N/A
13									
14									
15									
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20									
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22									
23									
24									
25									
26									
27									
28									
29									
30	TOTAL Year End	188,389,265	\$13.61	(\$0.68)	\$0.6225	191.54%			N/A

1/ Basic shares

2/ Basic earnings per share.

3/ Calculated on 12 months ended using closing stock price.

MONTANA EARNED RATE OF RETURN

Year: 2009

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service 1/	\$180,335,823	\$190,391,756	5.58%
3	108 (Less) Accumulated Depreciation 2/	108,535,171	112,744,420	3.88%
4				
5	NET Plant in Service	\$71,800,652	\$77,647,336	8.14%
6				
7	CWIP in Service Pending Reclassification	\$618,108	\$946,953	53.20%
8				
9	Additions			
10	151 Fuel Stocks	\$1,158,049	\$1,315,422	13.59%
11	154, 156 Materials & Supplies	1,618,232	1,591,503	-1.65%
12	165 Prepayments	28,148	38,327	36.16%
13	Other Additions			
14				
15	TOTAL Additions	\$2,804,429	\$2,945,252	5.02%
16				
17	Deductions			
18	190 Accumulated Deferred Income Taxes	\$11,510,738	\$12,919,790	12.24%
19	252 Customer Advances for Construction	488,748	476,099	-2.59%
20	255 Accumulated Def. Investment Tax Credits	73,752	16,298	-77.90%
21	Other Deductions			
22				
23	TOTAL Deductions	\$12,073,238	\$13,412,187	11.09%
24	TOTAL Rate Base	\$63,149,951	\$68,127,354	7.88%
25				
26	Net Earnings	\$5,092,091	\$5,738,359	12.69%
27				
28	Rate of Return on Average Rate Base	8.58%	8.74%	1.86%
29				
30	Rate of Return on Average Equity	11.13%	10.61%	-4.67%
31				
32	Major Normalizing Adjustments & Commission			
33	Rate-making adjustments to Utility Operations 3/			
34				
35	<u>Adjustment to Operating Revenues</u>			
36	Late Payment Revenues	\$14,172	\$14,768	4.21%
37	Gain from Disposition of Property 4/	3,302	3,406	3.14%
38				
39	<u>Adjustment to Operating Expenses</u>			
40	Elimination of Promotional & Institutional Advertising	(8,623)	(6,971)	19.16%
41	Elimination of Supplemental Insurance	(389,181)	96,473	124.79%
42	Elimination of 401K Tax Deduction	148,101	152,183	2.76%
43				
44	Total Adjustments to Operating Income	\$267,177	(\$223,511)	-183.66%
45				
46				
47	Adjusted Rate of Return on Average Rate Base	9.03%	8.40%	-6.98%
48				
49	Adjusted Rate of Return on Average Equity	12.05%	9.95%	-17.43%

1/ Excludes Acquisition Adjustment of \$2,601,533 for 2008 and \$2,620,153 for 2009.

2/ Excludes Acquisition Adjustment of \$2,312,758 for 2008 and \$2,386,118 for 2009.

3/ Updated amounts, net of taxes.

4/ Amortized over 5 years.

MONTANA COMPOSITE STATISTICS

Year: 2009

	Description	Amount
1		
2	Plant (Intrastate Only) (000 Omitted)	
3		
4	101 Plant in Service	\$182,781
5	107 Construction Work in Progress	13,691
6	114 Plant Acquisition Adjustments	
7	105 Plant Held for Future Use	
8	154, 156 Materials & Supplies	1,592
9	(Less):	
10	108, 111 Depreciation & Amortization Reserves	112,744
11	252 Contributions in Aid of Construction	476
12		
13	NET BOOK COSTS	\$84,844
14		
15	Revenues & Expenses (000 Omitted)	
16		
17	400 Operating Revenues	\$46,363
18		
19	403 - 407 Depreciation & Amortization Expenses	\$5,585
20	Federal & State Income Taxes	1,480
21	Other Taxes	3,079
22	Other Operating Expenses	30,480
23	TOTAL Operating Expenses	\$40,624
24		
25	Net Operating Income	\$5,739
26		
27	Other Income	1,032
28	Other Deductions	2,158
29		
30	NET INCOME	\$4,613
31		
32	Customers (Intrastate Only)	
33		
34	Year End Average:	
35	Residential	18,390
36	Small General	5,296
37	Large General	254
38	Other	186
39		
40	TOTAL NUMBER OF CUSTOMERS	24,126
41		
42	Other Statistics (Intrastate Only)	
43		
44	Average Annual Residential Use (Kwh))	8,910
45	Average Annual Residential Cost per (Kwh) (Cents) * 1/	\$0.079
46	* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47	Average Residential Monthly Bill	\$58.66
48	Gross Plant per Customer	\$7,576

1/ Reflects average revenue for 2009.

MONTANA CUSTOMER INFORMATION

Year: 2009

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Antelope	43	52	16	1	69
2	Bainville	153	100	42	7	149
3	Baker	1,695	953	339	13	1,305
4	Brockton	245	100	23	3	126
5	Carlyle	Not Available	2	5		7
6	Culbertson	716	346	144	4	494
7	Fallon	138	177	96	1	274
8	Fairview	709	391	92	3	486
9	Flaxville	87	55	25	3	83
10	Forsyth	1,944	1,031	282	10	1,323
11	Froid	195	138	48	4	190
12	Glendive	4,729	3,259	778	35	4,072
13	Homestead	Not Available	17	9	1	27
14	Ismay	26	24	17	1	42
15	Medicine Lake	269	165	52	4	221
16	Miles City	8,487	4,500	1,025	42	5,567
17	Outlook	82	49	35	12	96
18	Plentywood	2,061	941	259	6	1,206
19	Plevna	138	91	28	3	122
20	Poplar	911	874	174	16	1,064
21	Poplar Oil Field	Not Available		6	10	16
22	Redstone	Not Available	17	18	1	36
23	Reserve	37	25	13	3	41
24	Rosebud	Not Available	70	59	2	131
25	Savage	Not Available	134	31	2	167
26	Scobey	1,082	590	176	3	769
27	Sidney	4,774	2,324	483	24	2,831
28	Terry	611	352	102	10	464
29	Whitetail	Not Available	24	23	1	48
30	Wibaux	567	291	99	8	398
31	Wolf Point	2,663	1,470	343	10	1,823
32	Kinsey	Not Available	112	54	2	168
33	MT Oil Fields	Not Available	8	67	75	150
35	TOTAL Montana Customers	32,362	18,682	4,963	320	23,965

1/ 2000 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 2009

	Department	Year Beginning	Year End	Average
1	Electric	18	17	18
2	Gas	42	40(1)	41(1)
3	Accounting	19	8	14
4	Management	7	5	6
5	Service	47(1)	36	42(1)
6	Communications/Substation/Training	4	2	3
7	Power Production	29	31	30
8				
9				
10				
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41				
42				
43				
44	TOTAL Montana Employees	166(1)	139(1)	154(1)

1/ Parentheses denotes part-time.

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)**Year: 2009**

	Project Description	Total Company	Total Montana	
1	<u>Projects>\$1,000,000</u>			
2	<u>Common-Intangible</u>			
3	Replace Customer Information System	2,344,777	607,586	1/
4	<u>Electric-Steam Production</u>			
5	Replace U1 Boiling Bank Tubes at Heskett	1,450,616	360,079	1/
6	Purchase 25MW Wygen III Power Plant in WY	7,828,966	0	
9	<u>Electric-Other Production</u>			
10	Install 30MW Wind Generation in ND and MT	40,442,605	10,038,655	1/
11				
12	<u>Electric-Transmission</u>			
13	Purchase Land for a Transformer switch in Bismarck, ND	2,153,610	0	
	Construct New Heskett 230/115 Substation	10,995,816	1,704,036	1/
	Install 115 KV line in Bismarck, ND	2,091,089	0	
14	<u>Electric-Distribution</u>			
15	Construct Distribution Substation in Bismarck, ND	1,273,172	0	
	Construct Distribution Substation in Mandan, ND	1,764,227	0	
16	<u>Gas-Production</u>			
18	Install Gas Extraction Facility at Landfill in Billings, MT	8,502,470	2,421,081	1/
19				
20	<u>Other Projects<\$1,000,000</u>			
21	<u>Electric</u>			
22	Production	8,707,273	2,161,767	1/
23	Integrated Transmission	2,379,335	544,369	1/
24	Direct Transmission	2,117,284	370,247	2/
25	Distribution	16,056,867	3,480,408	2/
26	General	2,407,768	524,394	1/
27	Common:			
28	General Office	1,832,824	431,775	1/
29	Other Direct	188,915	42,396	2/
30	Total Electric	33,690,266	7,555,356	
31	<u>Gas</u>			
32				
33	Distribution	12,798,817	3,425,519	1/
34	General	2,041,375	517,477	2/
35	Common:			
36	General Office	1,226,817	363,587	1/
37	Other Direct	96,423	37,558	2/
38	Total Gas	16,163,432	4,344,141	
39	TOTAL	\$128,701,046	\$27,030,934	

1/ Allocated to Montana.

2/ Directly assigned to Montana.

TOTAL INTEGRATED SYSTEM & MONTANA PEAK AND ENERGY

Year: 2009

Integrated System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	15	900	431.9	256,851	2,782
2	Feb.	2	2000	401.8	222,667	4,584
3	Mar.	10	1100	413.7	239,748	2,253
4	Apr.	1	900	333.2	193,062	25
5	May	28	1500	326.4	193,700	11,172
6	Jun.	25	1700	418.4	209,641	11,654
7	Jul.	23	1700	439.4	219,323	2,001
8	Aug.	13	1700	473.7	219,055	3,473
9	Sep.	16	1700	427.5	210,779	6,194
10	Oct.	14	1300	347.1	224,261	27,717
11	Nov.	24	1900	350.1	205,836	14,183
12	Dec.	14	1900	459.5	264,136	4,751
13	TOTAL				2,659,059	90,789

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.	15	900	99.6	Not Available	Not Available
15	Feb.	2	2000	97.6		
16	Mar.	10	1100	101.8		
17	Apr.	1	900	84.2		
18	May	28	1500	79.9		
19	Jun.	25	1700	108.3		
20	Jul.	23	1700	114.2		
21	Aug.	13	1700	109.0		
22	Sep.	16	1700	103.3		
23	Oct.	14	1300	87.7		
24	Nov.	24	1900	91.0		
25	Dec.	14	1900	117.4		
26	TOTAL					

TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)	2,123,862	Sales to Ultimate Consumers (Include Interdepartmental)	2,663,560
2	Steam			
3	Nuclear		Requirements Sales for Resale	
4	Hydro - Conventional			
5	Hydro - Pumped Storage	79,803	Non-Requirements Sales for Resale	90,789
6	Other			
7	(Less) Energy for Pumping			
8	NET Generation	2,203,665		
9	Purchases	676,871		
10	Power Exchanges			
11	Received	25,809	Energy Furnished Without Charge	
12	Delivered	20,528		
13	NET Exchanges	5,281		
14	Transmission Wheeling for Other		Energy Used Within Electric Utility	
15	Received	1,665,423		
16	Delivered	1,564,167		
17	NET Transmission Wheeling	101,256	Total Energy Losses	196,089
18	Transmission by Others Losses	(36,635)		
19	TOTAL	2,950,438	TOTAL	2,950,438

Montana-Dakota's annual peak occurred during HE1700 August 13, 2009. All generation units were available for operation during the peak hour. The following units were on line and providing energy.

Heskett #1	21.0
Heskett #2	69.2
Lewis & Clark	39.9
Glendive Turbine	0.0
Coyote	96.0
Big Stone	108.0
Diamond Willow	0.0

Montana-Dakota also purchased 90.75 Mw from MISO to meet the peak demand. The remaining demand was purchased from Western Area Power Administration through Balancing Authority services and was paid back in-kind the following month.

SOURCES OF ELECTRIC SUPPLY

Year: 2009

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Combustion Turbine	Williston Plant	Williston, ND	8.6	(80.8)
2	Combustion Turbine	Miles City Turbine	Miles City, MT	24.2	(27.9)
3	Thermal	Lewis & Clark Station	Sidney, MT	53.1	316,532.0
4	Combustion Turbine	Glendive Turbine	Glendive, MT	78.0	1,949.7
5	Thermal	Heskett Station	Mandan, ND	104.0	556,756.6
6	Thermal	Big Stone Station	Milbank, SD	107.9	624,594.5
7				(MDU SHARE)	
8	Thermal	Coyote Station	Beulah, ND	106.7	625,979.0
9				(MDU SHARE)	
10	Wind	Diamond Willow	Baker, MT	19.6	67,690.5
11	Heat Recovery	Glen Ullin Ormat Sub	Glen Ullin, ND	6.0	10,271.1
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42					
43	Total			508.1	2,203,664.7

Outage Start Date/Time	Outage End Date/Time	Brief Description of Primary Cause 1/
<u>Big Stone Plant: Unit #1</u>		
03/06/2009 23:56	03/08/2009 00:56	Tube leak
03/19/2009 17:25	03/19/2009 20:26	High back pressure from air inleakage
03/19/2009 20:42	03/20/2009 07:58	High back pressure from air inleakage
05/27/2009 19:53	06/07/2009 02:20	Annual boiler outage
08/21/2009 23:52	08/23/2009 04:51	Fixing wall tube leak
09/09/2009 09:11	09/17/2009 22:23	Fixing extraction joint on 5th extraction
11/06/2009 18:53	11/08/2009 01:50	Tube leak repairs
<u>Coyote Station: Unit #1</u>		
01/22/2009 00:10	01/23/2009 12:29	Windbox air leak
03/19/2009 12:24	03/21/2009 00:24	Secondary superheat tube leak
03/25/2009 18:15	03/26/2009 23:00	Penthouse tube leak
03/26/2009 23:00	04/29/2009 00:00	Scheduled major outage - turbine and boiler work
04/29/2009 00:00	05/07/2009 08:51	Scheduled major outage - boiler and turbine work
05/07/2009 08:51	05/11/2009 12:39	Main steam lead drain leaks
05/18/2009 01:01	05/19/2009 07:10	Removing intercept valve temporary strainers
05/19/2009 12:36	05/19/2009 14:10	Voltage regulator testing
05/26/2009 17:27	05/28/2009 07:21	Wall tube leak
06/24/2009 20:00	07/18/2009 09:47	Generator inspection and repairs (step iron FOD)
08/27/2009 21:18	09/04/2009 07:46	Generator inspection and repairs
10/26/2009 03:41	10/27/2009 16:38	Primary super heat tube leak
12/03/2009 22:00	12/07/2009 07:02	Scheduled wash outage
<u>Lewis & Clark Station: Unit #1</u>		
03/01/2009 06:46	03/01/2009 17:34	Control valve problem
05/01/2009 21:49	05/15/2009 09:13	Planned Spring Outage
09/25/2009 21:58	10/02/2009 11:35	Planned Fall Outage
11/21/2009 06:19	11/21/2009 13:26	Installation of activated carbon injection nozzles
<u>R.M. Heskett Station: Unit #1</u>		
04/06/2009 12:21	04/12/2009 10:00	Maintenance Outage
08/02/2009 23:10	08/12/2009 23:29	Tripper spider pulley failed unable to fill coal bunkers.
12/25/2009 04:40	12/25/2009 17:13	Broken bus connection bracket (sub. trip on phase diff.)
12/28/2009 23:55	12/31/2009 02:57	Secondary superheater tube leaks
<u>R.M. Heskett Station: Unit #2</u>		
01/17/2009 02:00	01/30/2009 01:32	Water wall tube failure
03/20/2009 21:48	04/07/2009 15:12	Scheduled Maintenance Outage
04/07/2009 20:20	04/08/2009 03:58	MFT On Drum Level (Alarms were disabled)
08/02/2009 11:11	08/10/2009 06:46	Tripper spider pulley failed unable to fill coal bunkers.
12/25/2009 04:40	12/27/2009 01:40	Broken bus connection bracket (sub. trip on phase diff.)
12/27/2009 04:58	12/27/2009 13:31	Feedwater regulating valve caused high drum level trip

1/ Outages longer than 1 hour, other than reserve shutdowns for economic dispatch.

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2009

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWh)	Achieved Savings (MW & MWh)	Difference (MW & MWh)
1	MT Conservation & DSM Program (As Detailed on Schedule 35B)	\$14,670	\$11,923	23.04%	N/A	213 MWh	N/A
2							
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28							
29							
30							
31							
32	TOTAL	\$14,670	\$11,923	23.04%	N/A	213 MWh	N/A

ELECTRIC UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2009

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	Commercial Lighting	\$14,670	\$0	\$14,670	213 MWh	2009
3						
4						
5						
6						
7	Market Transformation					
8						
9						
10						
11						
12						
13	Renewable Resources					
14						
15						
16						
17						
18						
19	Research & Development					
20						
21						
22						
23						
24						
25	Low Income					
26	Discounts	\$205,697	\$0	\$205,697		2009
27						
28	Bill Assistance	45,000	0	45,000		2009
29						
30	Conservation	137,000	0	137,000		2009
31						
32	Furnace Safety	75,000	0	75,000		2009
33						
34	Education	3,062	0	3,062		2009
35	Large Customer Self Directed					
36		\$79,912	\$0	\$79,912		
37						
38						
39						
40						
41	Total	\$560,341	\$0	\$560,341	213 MWh	2009
42	Number of customers that received low income rate discounts			(Average)	1,258	
43	Average monthly bill discount amount (\$/mo)				\$13.63	
44	Average LIEAP-eligible household income				N/A	
45	Number of customers that received weatherization assistance				N/A	
46	Expected average annual bill savings from weatherization				N/A	
47	Number of residential audits performed				N/A	

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2009

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	Commercial Lighting	\$14,670	\$0	\$14,670	213 MWh	2009
3						
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
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28						
29	Low Income					
30						
31						
32						
33						
34						
35	Other					
36						
37						
38						
39						
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41						
42						
43						
44						
45						
46	Total	\$14,670	\$0	\$14,670	213 MWh	2009

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 36

MONTANA CONSUMPTION AND REVENUES

Year: 2009

	Sales of Electricity	Operating Revenues		MegaWatt Hours Sold		Avg. No. of Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	\$12,853,138	\$13,286,405	163,854	158,744	18,390	18,338
2	Small General	7,811,028	8,005,129	111,692	109,843	5,296	5,259
3	Large General	21,430,781	20,981,552	407,686	408,810	254	251
4	Lighting	788,279	786,236	10,013	9,913	81	85
5	Municipal Pumping	384,198	387,237	7,149	7,034	105	106
6	Sales to Other Utilities	650,909	2,339,802	Not Applicable	Not Applicable	Not Applicable	Not Applicable
7							
8							
9							
10							
11							
12							
13	TOTAL	\$43,918,333	\$45,786,361	700,394	694,344	24,126	24,039