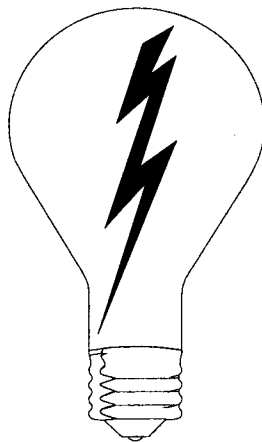


YEAR ENDING 2008

ANNUAL REPORT
OF
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

2008 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 2008 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-1 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: 2008

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:	Donald R. Ball
5a. Telephone Number:	(701) 222-7630
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	-
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		
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15		
16		
17		
18		

Officers

Year: 2008

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President & Chief	Executive	David L. Goodin
2	Executive Officer		
3			
4	Executive Vice President	Regulatory, Business Development and Gas Supply	Dennis L. Haider
5			
6			
7	Executive Vice President	Finance, Integration and Acquisitions	John F. Renner
8			
9	Vice President	Regulatory Affairs	Donald R. Ball
10			
11	Vice President	Electric Supply	Andrea L. Stomberg
12			
13	Vice President	Operations	Jay Skabo
14			
15	Vice President	Controller and Chief Accounting Officer	Garret Senger
16			
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CORPORATE STRUCTURE

Year: 2008

	Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
1	Montana-Dakota Utilities Co./	Electric and Natural Gas	\$53,529	18.27%
2	Great Plains Natural Gas Co.	Distribution		
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	148,693	50.75%
9		Natural Gas and Oil Production		
10				
11	Knife River Corporation	Construction Materials and	30,172	10.30%
12		Mining		
13				
14	MDU Construction Services	Construction Services	49,782	16.99%
15	Group, Inc.			
16				
17	Centennial Energy Resources LLC/	Other	10,812	3.69%
18	Centennial Holdings Capital Corp.			
19				
20				
21				
22				
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46				
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48				
49				
50	TOTAL		\$292,988	100.00%

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2008

	Items Allocated	Classification	Allocation Method	\$ to MT Utility	MT %	\$ to Other
1	Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	\$3,091	1.23%	\$247,266
2						
3	Advertising	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	1,812	1.21%	148,051
4						
5						
6	Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,412	1.21%	114,857
7						
8						
9	Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	694	1.93%	35,340
10						
11						
12	Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	4,278	1.22%	345,017
13						
14						
15	Computer Rental	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	340	3.05%	10,793
16						
17						
18	Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	25,534	2.21%	1,128,993
19						
20						
21	Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	42,467	1.81%	2,305,143
22						
23						
24	Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,838	1.41%	128,932
25						
26						
27	Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a Combination of Net Plant Investment and Number of Employees	12,003	0.88%	1,359,532
28						
29						
30						
31	Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on Number of Employees	4,818	1.48%	320,294
32						

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2008

	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	2,480	1.10%	222,747
2						
3						
4	Employee Reimbursable Expenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	3,228	1.48%	214,419
5						
6						
7	Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	19,399	1.22%	1,572,356
8						
9						
10	Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	47	1.62%	2,862
11						
12						
13	Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,254	1.35%	91,833
14						
15						
16	Moving Expense	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	170	1.07%	15,734
17						
18						
19	Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,523	1.16%	129,686
20						
21						
22	Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	2,728	2.04%	131,058
23						
24						
25	Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience	19,101	1.14%	1,652,740
26						
27						
28	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	508	1.71%	29,198
29						

SCHEDULE 5

Company Name: **Montana-Dakota Utilities Co.**

CORPORATE ALLOCATIONS - ELECTRIC

Year: 2008

Items Allocated		Classification	Allocation Method		\$ to MT Utility	MT %	\$ to Other
1	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred		263	1.50%	17,240
2							
3							
4	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred		312,973	1.57%	19,593,475
5							
6							
7	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred		150	2.09%	7,016
8							
9							
10	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred		2,083	1.38%	148,329
11							
12							
13	Reimbursements and	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred		(2,654)	13.00%	(17,766)
14	Waranty Credits						
15							
16	Supplemental Insurance	Administrative & General	Various Corporate Overhead Allocation Factors		72,867	1.20%	5,995,555
17							
18	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred		2,104	1.65%	125,759
19	Registrations						
20							
21	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred		8,255	1.71%	474,971
22							
23							
24	Telephone & Cell Phones	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred		2,944	1.31%	221,099
25							
26							
27	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred		1,425	1.94%	72,134
28							
29							
30							
31	TOTAL				\$549,135	1.47%	\$36,844,663

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC Year: 2008

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		Materials		\$3,678		\$921
3		Other Reimbursable Exp		7		2
4		Network Circuit Charges		4,518		1,042
5		Office Services		4		1
6						
7		Capital	Actual Costs Incurred			
8		Materials		949		220
9		Contract Services		404		
10		Office Services		3,266		757
11		Other Reimbursable Exp		9		2
12						
13		Other Transactions/Reimbursements				
14		Miscellaneous		6,372,229		
15						
16						
17		Total Knife River Corporation Operating Revenues for the Year 2008			\$1,640,683,000	
18		Excludes Intersegment Eliminations				
19						
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$6,385,064	0.3892%	\$2,945

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC Year: 2008

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		Contract Services		\$6,693		\$2,309
3		Other Reimbursable Exp		69		16
4		Damages		16,712		0
5						
6		Capital	Actual Costs Incurred	1,375		
7		Other				
8						
9		Other Transactions/Reimbursements	Actual Costs Incurred	2,225		
10		Miscellaneous		1,606		
11		Auto Clearing				
12						
13						
14		Total WBI Operating Revenues for the Year 2008			\$1,244,432,000	
15		Excludes Intersegment Eliminations				
16						
17						
18						
19						
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$28,680	0.0023%	\$2,325

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2008

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	\$650		\$8
2		Materials				
3		Capital				
4		Materials	Actual Costs Incurred	487		98
5		Contract Services		11,324		0
6						
7		Other Transactions/Reimbursements				
8		Miscellaneous	Actual Costs Incurred	1,073,393		
9		Auto and Work		10,329		
10						
11						
12						
13		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2008			\$1,257,319,000	
14		Excludes Intersegment Eliminations				
15						
16						
17						
18						
19						
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$1,096,183	0.0872%	\$106

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2008

Line No.	(a) Affiliate Name	(b)	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	CENTENNIAL ENERGY					
2	RESOURCES	Other Transactions/Reimbursements	Actual Costs Incurred			
3		Miscellaneous		\$656,515		
4						
5		Total Centennial Energy Resources Operating Revenues for the Year 2008			\$0	
6		Excludes Intersegment Eliminations				
7						
8						
9						
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11						
12						
13						
14						
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20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$656,515	0.0000%	\$0

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 2008

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			
2	CAPITAL, LLC	Corporate Aircraft	Allocation Factors and/or	\$178,724		\$42,588
3		Rent	Actual Costs Incurred	288,041		66,456
4		Cost of Service		102,797		23,717
5						
6		Capital	Actual Costs Incurred			
7		Corporate Aircraft		22,172		7,318
8		Contract Services		34,834		8,074
9		Materials		760,284		176,224
10						
11		Other Transactions/Reimbursements	Actual Costs Incurred			
12		Corporate Aircraft		100,071		
13		Computer		128,308		
14						
15						
16		Total Centennial Holdings Capital, LLC Operating Revenues for the Year 2008			\$10,501,000	
17		Grand Total Affiliate Transactions				
18						
19						
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$1,615,231	15.3817%	\$324,377

* 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 TO UTILITY - ELECTRIC

Year: 2008

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	Capital	Actual Costs Incurred			
2		Meals and Entertainment		\$103		\$24
3		Other Transactions/Reimbursements	Actual Costs Incurred	176,823		
4		Miscellaneous				
5						
6						
7						
8		Total MDU Energy Capital Operating Revenues for the Year 2008			\$626,346,000	
9		Grand Total Affiliate Transactions				
10						
11						
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13						
14						
15						
16						
17						
18						
19						
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		\$176,926	0.0282%	\$24

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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		\$87,619		
4		Advertising		52,778		
5		Air Service		42,837		
6		Automobile		9,043		
7		Bank Services		122,539		
8		Corporate Aircraft		47,280		
9		Consultant Fees		430,546		
10		Contract Services		1,133,134		
11		Computer Rental		4,466		
12		Directors Expenses		518,156		
13		Employee Benefits		113,946		
14		Employee Meeting		81,776		
15		Employee Reimbursable Expense		73,049		
16		Express Mail		531		
17		Insurance		526,498		
18		Legal Retainers & Fees		559,269		
19		Moving Allowance		5,795		
20		Meal Allowance		1,091		
21		Cash Donations		21,540		
22		Meals & Entertainment		31,956		
23		Industry Dues & Licenses		46,788		
24		Office Expenses		50,205		
25		Supplemental Insurance		2,103,360		
26		Permits & Filing Fees		10,218		
27		Postage		5,370		
28		Payroll		7,042,495		
29		Reference Materials		51,793		
30		Rental		1,011		
31		Seminars & Meeting Registrations		47,417		
32		Software Maintenance		217,986		
33		Telephone Expenses		99,657		
34		Training		24,897		
35		Total MDU Resources Group, Inc.		\$13,565,046	0.8597%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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.				
2		Communications Department	* Various Corporate Overhead Allocation Factors, Cost of Service Factors, Time Studies and /or Actual Costs Incurred	2,951		
3		Network Circuit Charges				
4						
5						
6						
7		Office Services	* General Office Complex and Office Supplies Cost of Service Allocation Factors	1,758		
8		Contract Services		12,327		
9		Express Mail		363		
10		Rental of Office Equipment		106		
11		Office Expenses		7,306		
12		Postage		339,760		
13		Cost of Service - General Office Buildings				\$75,348
14						
15						
16		Other Miscellaneous Departments	* Various Corporate Overhead Allocation Factors and /or Actual Costs Incurred	4		
17		Payroll				
18						
19						
20		Transportation & Procurement	* Various Corporate Overhead Allocation Factors and /or Actual Costs Incurred	1		
21		Office Expenses		9		
22		Utilities				
23						
24		Other Direct Charges	Actual Costs Incurred	56,524		7,046
25		Employee Discounts		14,367		
26		Permits & Filing Fees		107,634		
27		Electric Consumption		97,686		
28		Gas Consumption		79,079		
29		Miscellaneous		1,198,314		63,609
30		Computer/Software Support		35,450		907
31		Network Circuit Charges				
32						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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	Audit Costs		651,937		
2		Telephone Charges		33,025		
3		Employee Reimbursable Exp		46,186		
4		Misc Employee Benefits		25,402		
5		Contract Services		20,878		
6					0.1731%	\$146,910
7		Total Montana-Dakota Utilities Co.		\$2,731,067		
8						
9		OTHER TRANSACTIONS/REIMBURSEMENTS				
10						
11		Insurance		99,740		
12		Federal & State Tax Liability Payments		563,321		
13		Tax Deferred Savings Plan		110,490		
14		Miscellaneous Reimbursements		(289,729)		
15						
16		Total Other Transactions/Reimbursements		\$483,822		
17						
18		Grand Total Affiliate Transactions		\$16,779,935		\$146,910
19						
20		Total Knife River Corporation Operating Expenses for 2008 - Excludes Intersegment Eliminations			\$1,577,834,000	

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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: 2008

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		\$89,249		
4		Advertising		53,589		
5		Air Service		38,023		
6		Automobile		16,594		
7		Bank Services		124,667		
8		Corporate Aircraft		45,222		
9		Consultant Fees		364,139		
10		Contract Services		587,935		
11		Computer Rental		3,204		
12		Directors Expenses		516,340		
13		Employee Benefits		112,696		
14		Employee Meeting		81,672		
15		Employee Reimbursable Expense		78,796		
16		Express Mail		255		
17		Insurance		623,514		
18		Legal Retainers & Fees		568,538		
19		Meal Allowance		966		
20		Cash Donations		21,634		
21		Meals & Entertainment		34,204		
22		Moving Expense		5,784		
23		Industry Dues & Licenses		47,216		
24		Office Expenses		43,065		
25		Supplemental Insurance		2,153,099		
26		Permits & Filing Fees		10,374		
27		Postage		5,566		
28		Payroll		6,923,662		
29		Reference Materials		52,840		
30		Rental		4,383		
31		Seminars & Meeting Registrations		43,593		
32		Software Maintenance		150,957		
33		Telephone		78,630		
34		Training Material		25,557		
35		Total MDU Resources Group, Inc.		\$12,905,963	1.3011%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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	* Various Corporate Overhead			
3		Expense	Allocation Factors, Cost of			
4		Network Circuit Charges	Service Factors, Time	\$2,906		
5			Studies and /or Actual Costs			
6						
7		Office Services	* General Office Complex and	1,749		
8		Expense	Office Supplies cost of	361		
9		Contract Services	Service Allocation Factors			
10		Rental of Office Equipment		12,161		
11		Express Mail		242		
12		Office Expenses		7,270		
13		Postage		305,659		
14		Cost of Service - General Office Buildings				\$67,785
15						
16		Region Operations	* Various Corporate Overhead			
17		Expense	Allocation Factors and/or			
18		Automobile	Actual Costs Incurred	\$3,599		
19		Contract Services		1,933		
20		Custodial Services & Supplies		55		
21		Materials		1,453		
22		Meals & Entertainment		134		
23		Other Reimburseable Expenses		273		
24		Office Telephone		5,970		
25		Payroll		8,817		
26		Rent		349		
27		Annual Easements		2,975		
28		Freight		2		
29		Utilities		2,129		
30		General & Administrative Expenses		4,045		
31		Permits		78		

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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.	Clearing Accounts	* Various Corporate Overhead Allocation Factors, Time Studies and/or Actual Costs Incurred	\$3	
2		Office Expenses		247	
3		Office Telephone		3	
4		Permits & Filing Fees		13	
5		Utilities			
6		Expense			
7		Office Expenses		3	
8		Utilities		28	
9					
10		Other Direct Charges	Actual Costs Incurred	171,762	\$103,267
11		Utility/Merchandise Discounts		413,135	
12		Audit Costs		74,230	
13		Contract Maintenance Services		2,017	
14		Radio Maintenance		16,890	
15		Vehicle Maintenance		24,234	
16		Permits & Filing Fees		13,125	
17		Misc Employee Benefits		315,632	
18		Computer/Software Support		16,039	
19		Catholic Protection		210,092	
20		Purchased Power for Compressor Stations		1,077,081	
21		Electric Compressor - Electricity Cost		287,227	
22		Office Building Utilities		16,017	
23		Legal Fees		29,061	
24		Employee Reimbursable Exp		11,722	
25		Telephone Charges		128,329	
26		Miscellaneous		22,380	
27		BitterCreek Projects			9,861
					22,380

Year: 2008

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.				
2					
3		Total Montana-Dakota Utilities Co.	\$3,191,430	0.3217%	\$1,283,502
4					
11		OTHER TRANSACTIONS/REIMBURSEMENTS			
12		Insurance	(Actual Costs Incurred)		
13		Federal & State Tax Liability Payments	(\$6,513)		
14		Tax Deferred Savings Plan	71,640,182		
15		Miscellaneous Reimbursements	9,108		
16		Total Other Transactions/Reimbursements	(65,996)	7.2160%	
17			\$71,576,781		
18		Grand Total Affiliate Transactions	\$87,674,174	8.8389%	\$1,283,502
19					
20					
21					
22		Total WBI Holdings Operating Expenses for 2008 - Excludes Intersegment Eliminations		\$991,918,000	

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AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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		\$20,645		
4		Advertising		12,446		
5		Air Service		11,490		
6		Automobile		1,794		
7		Bank Services		28,881		
8		Corporate Aircraft		10,562		
9		Consultant Fees		68,180		
10		Contract Services		122,593		
11		Computer Rental		426		
12		Directors Expenses		123,285		
13		Employee Benefits		25,268		
14		Employee Meeting		19,365		
15		Employee Reimbursable Expense		18,267		
16		Express Mail		455		
17		Insurance		126,518		
18		Legal Retainers & Fees		131,841		
19		Moving Allowance		1,372		
20		Meal Allowance		240		
21		Cash Donations		5,094		
22		Meals & Entertainment		7,626		
23		Industry Dues & Licenses		11,116		
24		Office Expenses		8,931		
25		Supplemental Insurance		494,952		
26		Permits & Filing Fees		2,396		
27		Postage		1,269		
28		Payroll		1,905,025		
29		Reference Materials		12,258		
30		Rent		237		
31		Seminars & Meeting Registrations		8,877		
32		Software Maintenance		26,751		
33		Telephone		11,306		
34		Training Material		5,559		
35		Total MDU Resources Group, Inc.		\$3,225,025	0.2743%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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	\$32		
3		Air Service	Allocation Factors, Cost of	33		
4		Automobile	Service Factors, Time Studies	3		
5		Contract Services	and/or Actual Costs Incurred	27		
6		Meals & Entertainment		1,238		
7		Office Expenses		33,479		
8		Office Telephone		10,486		
9		Payroll		106		
10		Employee Reimbursable Expense		302		
11		Materials		32		
12		Annual Easements		2		
13		Utilities		23		
14		Industry Dues & Licenses		75		
15		Seminars & Meeting Registrations				
16						
17		Office Services	* General Office Complex and	417		
18		Contract Services	Office Supplies Cost of Service	86		
19		Rental of Office Equip	Allocation	2,917		
20		Express Mail		30		
21		Office Expenses		1,728		
22		Postage		125,366		
23		Cost of Service - General Office Buildings				\$27,802
24						
25		Transportation Department	* Various Corporate Overhead	1		
26		Office Supplies	Allocation Factors, Time Studies	14		
27		Utilities	and/or Actual Costs Incurred	(6)		
28						
29						
30		Prior Year Payroll Correction				
31						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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 Direct Charges	Actual Costs Incurred			
2		Legal Fees		\$6,306		\$1,128
3		Air Service		2,799		
4		Computer/Software Support		24,213		
5		Employee Reimbursable Expense		938		
6		Meals & Entertainment		35		
7		Misc Employee Benefits		160,156		12,598
8		Office Expenses		2,860		2,777
9		Permits and Filing fees		12,801		
10		Telephone		1,565		
11		Miscellaneous		(163,354)		
12		Employee Discounts		3,716		
13		Gas Consumption		3,437		3,437
14		Total Montana-Dakota Utilities Co.		\$231,863	0.0197%	\$47,742
15		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
16		Federal & State Tax Liability Payments		\$34,295,528		
17		Insurance		18,081		
18		Miscellaneous Reimbursements		(436,651)		(\$14,217)
19		KESOP Carrying Costs		(116,142)		
20						
21						
22		Total Other Transactions/Reimbursements		\$33,760,816	2.8712%	(\$14,217)
23		Grand Total Affiliate Transactions		\$37,217,704	3.1652%	\$33,525
24						
25		Total MDU Construction Services Group, Inc. Operating Expenses for 2008				
26		Excludes Intersegment Eliminations				
27						
28					\$ 1,175,834,000	

* 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: 2008

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	MDU RESOURCES GROUP, INC.	* Various Corporate Overhead Allocation Factors, Time Studies and/or Costs Incurred			
2	RESOURCES	Corporate Overhead				
3		Audit Costs		\$4,581		
4		Advertising		2,775		
5		Air Service		1,537		
6		Automobile		359		
7		Bank Services		6,421		
8		Corporate Aircraft		2,393		
9		Consultant Fees		14,543		
10		Contract Services		26,536		
11		Computer Rental		95		
12		Directors Expenses		29,054		
13		Employee Benefits		5,542		
14		Employee Meeting		4,425		
15		Employee Reimbursable Expense		2,829		
16		Express Mail		4		
17		Insurance		4,822		
18		Legal Retainers & Fees		29,345		
19		Cash Donations		1,154		
20		Meals & Entertainment		1,401		
21		Meal Allowance		46		
22		Moving		314		
23		Industry Dues & Licenses		2,470		
24		Office Expenses		1,644		
25		Supplemental Insurance		108,993		
26		Permits & Filing Fees		550		
27		Postage		271		
28		Payroll		(58,743)		
29		Reference Materials		2,677		
30		Rental		51		
31		Seminars & Meeting Registrations		1,889		
32		Software Maintenance		5,229		
33		Telephone		2,134		
34		Training		1,008		
35		Total MDU Resources Group, Inc.		\$206,349	10.4375%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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	RESOURCES	Communications Department	* Various Corporate Overhead	\$149		
3		Office Telephone	Allocation Factors, Cost of Service			
4			Factors, Time Studies and/or			
5			Actual Costs Incurred			
6						
7		Office Services	* General Office Complex and Office	96		
8		Contract Services	Supplies Cost of Service	714		
9		Express Mail	Allocation Factors	399		
10		Postage		20		
11		Rental of Office Equipment		11,431		
12		Cost of Service - General Office Buildings				\$2,535
13						
14		Prior Year Payroll Correction		(129)		
15						
16		Other Direct Charges	Actual costs incurred			
17		Audit Costs		34,208		
18		Permits and Filing Fees		68,330		
19		Employee Benefits		137,992		
20		Corporate/Commercial Air Service		20,232		
21		Employee Reimbursable Exp		55		
22		Meals & Entertainment		24		
23		Office Supplies		(1,131)		
24		Miscellaneous		135		
25		Total Montana-Dakota Utilities Co.		\$272,525	13.7848%	\$2,535

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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					
2		OTHER TRANSACTIONS/REIMBURSEMENTS				
3		Federal & State Tax Liability Payments		(782,880)		
4		Miscellaneous Reimbursements		(661)		
5		Total Other Transactions/Reimbursements		(\$783,541)		
6						
7		Grand Total Affiliate Transactions		(\$304,667)	-15.4106%	\$2,535
8						
9		Total Centennial Energy Resources Operating Expenses for 2008			\$1,977,000	
10		Excludes Intersegment Eliminations				

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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: 2008

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				
5		Aircraft Sale				
6		Computer/Software Costs		\$315,869		
7		Employee Reimbursable Exp and Fuel		535,256		
8		Telephone		17,515		
9		Electric Consumption		147,481		
10		Gas Consumption		9,717		
11		Office Expenses		795		
12		Miscellaneous		4,209		
13		Total Montana-Dakota Utilities Co.		\$1,030,842	18.2871%	
14		OTHER TRANSACTIONS/REIMBURSEMENTS				
15		Payroll				
16		Federal & State Tax Liability Payments		\$616,083		
17		Total Other Transactions/Reimbursements		(3,504,046)		
18				(\$2,887,963)		
19		Grand Total Affiliate Transactions		(\$1,857,121)	-32.9452%	
20						
21		Total CHCC Operating Expenses for 2008			\$5,637,000	
22		Excludes Intersegment Eliminations				

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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					
2	CAPITAL **	MDU RESOURCES GROUP, INC.				
3		Corporate Overhead	* Various Corporate Overhead Allocation Factors, Time Studies and/or Actual Costs Incurred	\$24,398		
4		Audit Costs		14,286		
5		Advertising		11,497		
6		Air Service		1,935		
7		Automobile		33,757		
8		Bank Services		10,916		
9		Corporate Aircraft		80,706		
10		Consultant Fees		151,341		
11		Contract Services		327		
12		Computer Rental		92,418		
13		Directors Expenses		30,508		
14		Employee Benefits		18,868		
15		Employee Meeting		18,920		
16		Employee Reimbursable Expense		19		
17		Express Mail		161,410		
18		Insurance		153,007		
19		Legal Retainers & Fees		204		
20		Meal Allowance		5,262		
21		Cash Donations		7,982		
22		Meals & Entertainment		1,329		
23		Moving Expense		11,652		
24		Industry Dues & Licenses		8,945		
25		Office Expenses		725,466		
26		Supplemental Insurance		2,261		
27		Permits & Filing Fees		1,733		
28		Postage		1,673,440		
29		Payroll		14,771		
30		Reference Materials		330		
31		Rental		9,884		
32		Seminars & Meeting Registrations		18,859		
33		Software Maintenance		9,664		
34		Telephone		5,568		
35		Training Material				
		Total MDU Resources Group, Inc.		\$3,301,663	0.5831%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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					
2	CAPITAL **	MONTANA-DAKOTA UTILITIES CO.				
3		Communications Department				
4		Office Telephone	* Various Corporate Overhead Allocation Factors, Cost of Service Factors, Time Studies and/or Actual Costs Incurred	\$607		
5						
6						
7		Office Services	* General Office Complex and Office Supplies Cost of Service Allocation	388		
8		Contract Services		80		
9		Rental of Office Equip		2,567		
10		Express Mail		1,620		
11		Postage		84,489		
12		Cost of Service - General Office Buildings				\$18,737
13						
14		Finance	* Various Corporate Overhead Allocation Factors, Cost of Service Factors, Time Studies and/or Actual Costs Incurred	75		
15		Air Services		586		
16		Corporate Aircraft		98,524		
17		Payroll		38		
18		Employee Reimbursable Expense		60		
19		Meals & Entertainment		15		
20		Reference Materials				
21						
22		Accounting	* Various Corporate Overhead Allocation Factors, Cost of Service Factors, Time Studies and/or Actual Costs Incurred	17,916		
23		Payroll		51		
24		Employee Reimbursable Expense		82		
25		Meals & Entertainment		33		
26		Reference Materials				
27						
28		President & CEO	* Various Corporate Overhead Allocation Factors, Cost of Service Factors, Time Studies and/or Actual Costs Incurred	319,535		
29		Payroll		1,670		
30		Employee Reimbursable Expense		216		
31		Meals & Entertainment		336		
32		Reference Materials				

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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	President & CEO cont.				
2	CAPITAL **	Meals Allowance		\$6		
3		Air Service		1,679		
4		Industry Dues & Licenses		175		
5		Corporate Aircraft		2,070		
6		Office Supplies		287		
7						
8		Prior Year Payroll Correction		597		
9						
10		OTHER TRANSACTIONS/REIMBURSEMENTS				
11		Other Direct Charges	Actual costs incurred			
12		Employee Benefits		135,425		
13		Audit Costs		265,460		
14		Corporate/Commercial Air Service		74,009		
15		Computer/Software Costs		901,482		
16		Legal Fees		29,008		
17		Consulting Fees		909,946		
18		Contract Services		132,295		
19		Meals & Entertainment		7,097		
20		Employee Reimbursable Exp		64,436		
21		Industry Dues & Licenses		133,859		
22		Telephone Expense		5,808		
23		Reallocation of Cross Charges		234,456		
24		Miscellaneous		25,226		
25		Total Montana-Dakota Utilities Co.		\$3,452,209	0.6097%	\$18,737

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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	Payroll		\$242,201		
2	CAPITAL **	Federal & State Tax Liability Payments		(1,847,651)		
3		Miscellaneous Reimbursements		(36,133)		
4		Total Other Transactions/Reimbursements		(\$1,641,583)	-0.2899%	
5						
6		Grand Total Affiliate Transactions		\$5,112,289	0.9028%	\$18,737
7						
8		Total MDU Energy Capital Operating Expenses for 2008			\$566,247,000	
9		Excludes Intersegment Eliminations				

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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 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: 2008

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		\$123,984		
5		Permits and Filing Fees		12,417		
6		Employee Reimbursable Exp		617		
7		Miscellaneous		135,715		
8		Total Montana-Dakota Utilities Co.		\$272,733	0.000%	\$0
9						
10		Grand Total Affiliate Transactions		\$272,733	0.000%	\$0
11						
12						
13						

MONTANA UTILITY INCOME STATEMENT

Year: 2008

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	\$40,103,934	\$47,668,373	18.86%
2				
3	Operating Expenses			
4	401 Operation Expenses	\$27,131,075	\$28,398,142	4.67%
5	402 Maintenance Expense	3,733,467	3,964,001	6.17%
6	403 Depreciation Expense	5,325,796	5,338,661	0.24%
7	404-405 Amortization of Electric Plant	349,835	288,124	-17.64%
8	406 Amort. of Plant Acquisition Adjustments	102,309	103,749	1.41%
9	407 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Study Costs			
11	408.1 Taxes Other Than Income Taxes	2,768,367	3,184,308	15.02%
12	409.1 Income Taxes - Federal	136,357	(943,895)	-792.22%
13	- Other	(50,195)	(110,721)	-120.58%
14	410.1 Provision for Deferred Income Taxes	(551,803)	1,984,787	459.69%
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	(30,770)	369,126	1299.63%
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	\$38,914,438	\$42,576,282	9.41%
21	NET UTILITY OPERATING INCOME	\$1,189,496	\$5,092,091	328.09%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Electricity			
2	440 Residential	\$11,661,381	\$13,286,405	13.94%
3	442 Commercial & Industrial - Small	6,750,592	8,005,129	18.58%
4	Commercial & Industrial - Large	17,245,513	20,981,552	21.66%
5	444 Public Street & Highway Lighting	689,417	786,236	14.04%
6	445 Other Sales to Public Authorities	320,805	387,237	20.71%
7	446 Sales to Railroads & Railways			
8	448 Interdepartmental Sales			
9	Net Unbilled Revenue	332,738	(216,190)	-164.97%
10	TOTAL Sales to Ultimate Consumers	\$37,000,446	\$43,230,369	16.84%
11	447 Sales for Resale	1,649,663	2,443,467	48.12%
12				
13	TOTAL Sales of Electricity	\$38,650,109	\$45,673,836	18.17%
14	449.1 (Less) Provision for Rate Refunds			
15				
16	TOTAL Revenue Net of Provision for Refunds	\$38,650,109	\$45,673,836	18.17%
17	Other Operating Revenues			
18	450 Forfeited Discounts & Late Payment Revenues			
19	451 Miscellaneous Service Revenues	\$2,261	\$18,648	724.77%
20	453 Sales of Water & Water Power			
21	454 Rent From Electric Property	839,716	820,415	-2.30%
22	455 Interdepartmental Rents			
23	456 Other Electric Revenues	611,848	1,155,474	88.85%
24				
25	TOTAL Other Operating Revenues	\$1,453,825	\$1,994,537	37.19%
26	Total Electric Operating Revenues	\$40,103,934	\$47,668,373	18.86%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

Account Number & Title		Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	\$488,025	\$529,205	8.44%
6	501 Fuel	10,313,503	12,849,201	24.59%
7	502 Steam Expenses	924,086	970,116	4.98%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	293,016	314,439	7.31%
11	506 Miscellaneous Steam Power Expenses	678,777	740,424	9.08%
12	507 Rents	89	78	-12.36%
13				
14	TOTAL Operation - Steam	12,697,496	15,403,463	21.31%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	192,385	207,036	7.62%
18	511 Maintenance of Structures	140,916	141,740	0.58%
19	512 Maintenance of Boiler Plant	1,103,027	1,427,485	29.42%
20	513 Maintenance of Electric Plant	195,966	257,245	31.27%
21	514 Maintenance of Miscellaneous Steam Plant	241,218	274,382	13.75%
22				
23	TOTAL Maintenance - Steam	1,873,512	2,307,888	23.19%
24				
25	TOTAL Steam Power Production Expenses	\$14,571,008	\$17,711,351	21.55%
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: 2008

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	\$26,630	\$37,195	39.67%
27	547 Fuel	587,137	222,792	-62.05%
28	548 Generation Expenses	378	47,926	12578.84%
29	549 Miscellaneous Other Power Gen. Expenses	106,465	67,640	-36.47%
30	550 Rents		939	100.00%
31				
32	TOTAL Operation - Other	720,610	376,492	-47.75%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	20,627	21,122	2.40%
36	552 Maintenance of Structures	1,284	1,264	-1.56%
37	553 Maintenance of Generating & Electric Plant	284,092	44,551	-84.32%
38	554 Maintenance of Misc. Other Power Gen. Plant	(26)	13	150.00%
39				
40	TOTAL Maintenance - Other	305,977	66,950	-78.12%
41				
42	TOTAL Other Power Production Expenses	\$1,026,587	\$443,442	-56.80%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	\$5,702,867	\$4,298,525	-24.63%
46	556 System Control & Load Dispatching	295,589	288,342	-2.45%
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	\$5,998,456	\$4,586,867	-23.53%
50				
51	TOTAL Power Production Expenses	\$21,596,051	\$22,741,660	5.30%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

Account Number & Title			Last Year	This Year	% Change
1	Transmission Expenses				
2	Operation				
3	560	Operation Supervision & Engineering	\$335,248	\$381,949	13.93%
4	561	Load Dispatching	308,941	354,509	14.75%
5	562	Station Expenses	131,241	144,005	9.73%
6	563	Overhead Line Expenses	19,705	38,901	97.42%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	114,408	127,337	11.30%
9	566	Miscellaneous Transmission Expenses	31,643	36,357	14.90%
10	567	Rents	167,891	170,442	1.52%
11	575	Day-Ahead and Real-Time Market Administration	90,532	106,046	17.14%
12					
13	TOTAL Operation - Transmission		1,199,609	1,359,546	13.33%
14	Maintenance				
15	568	Maintenance Supervision & Engineering	19,483	15,489	-20.50%
16	569	Maintenance of Structures			
17	570	Maintenance of Station Equipment	117,899	131,180	11.26%
18	571	Maintenance of Overhead Lines	216,410	218,293	0.87%
19	572	Maintenance of Underground Lines			
20	573	Maintenance of Misc. Transmission Plant			
21					
22	TOTAL Maintenance - Transmission		353,792	364,962	3.16%
23					
24	TOTAL Transmission Expenses		\$1,553,401	\$1,724,508	11.01%
25	Distribution Expenses				
26	Operation				
27					
28	580	Operation Supervision & Engineering	\$303,325	\$292,877	-3.44%
29	581	Load Dispatching			
30	582	Station Expenses	79,493	121,316	52.61%
31	583	Overhead Line Expenses	94,913	12,549	-86.78%
32	584	Underground Line Expenses	123,464	158,233	28.16%
33	585	Street Lighting & Signal System Expenses	9,820	4,164	-57.60%
34	586	Meter Expenses	195,177	190,053	-2.63%
35	587	Customer Installations Expenses	125,493	118,571	-5.52%
36	588	Miscellaneous Distribution Expenses	504,477	500,230	-0.84%
37	589	Rents	28,132	25,275	-10.16%
38					
39	TOTAL Operation - Distribution		1,464,294	1,423,268	-2.80%
40	Maintenance				
41	590	Maintenance Supervision & Engineering	156,615	136,163	-13.06%
42	591	Maintenance of Structures			
43	592	Maintenance of Station Equipment	33,434	37,653	12.62%
44	593	Maintenance of Overhead Lines	488,219	549,563	12.56%
45	594	Maintenance of Underground Lines	197,902	164,760	-16.75%
46	595	Maintenance of Line Transformers	44,518	48,620	9.21%
47	596	Maintenance of Street Lighting, Signal Systems	44,291	52,366	18.23%
48	597	Maintenance of Meters	7,047	18,752	166.10%
49	598	Maintenance of Miscellaneous Dist. Plant	95,662	98,737	3.21%
50					
51	TOTAL Maintenance - Distribution		1,067,688	1,106,614	3.65%
52					
53	TOTAL Distribution Expenses		\$2,531,982	\$2,529,882	-0.08%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

Account Number & Title		Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	\$91,896	\$102,250	11.27%
4	902 Meter Reading Expenses	237,437	184,578	-22.26%
5	903 Customer Records & Collection Expenses	435,464	419,957	-3.56%
6	904 Uncollectible Accounts Expenses	45,499	40,739	-10.46%
7	905 Miscellaneous Customer Accounts Expenses	84,500	74,661	-11.64%
8				
9	TOTAL Customer Accounts Expenses	\$894,796	\$822,185	-8.11%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	\$3,655	\$10,970	200.14%
14	908 Customer Assistance Expenses	6,969	9,708	39.30%
15	909 Informational & Instructional Adv. Expenses	6,850	3,330	-51.39%
16	910 Miscellaneous Customer Service & Info. Exp.	15	5	-66.67%
17				
18	TOTAL Customer Service & Info Expenses	\$17,489	\$24,013	37.30%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision	\$15,327	\$11,964	-21.94%
23	912 Demonstrating & Selling Expenses	26,767	33,319	24.48%
24	913 Advertising Expenses	3,139	1,674	-46.67%
25	916 Miscellaneous Sales Expenses	8,905	7,837	-11.99%
26				
27	TOTAL Sales Expenses	\$54,138	\$54,794	1.21%
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	\$1,352,969	\$1,160,831	-14.20%
32	921 Office Supplies & Expenses	532,187	622,844	17.03%
33	922 (Less) Administrative Expenses Transferred - Cr.			
34	923 Outside Services Employed	170,604	119,269	-30.09%
35	924 Property Insurance	134,663	107,989	-19.81%
36	925 Injuries & Damages	273,949	136,083	-50.33%
37	926 Employee Pensions & Benefits	1,436,660	1,954,171	36.02%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	17,073	126,133	638.79%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	18,127	12,553	-30.75%
42	930.2 Miscellaneous General Expenses	101,963	35,226	-65.45%
43	931 Rents	45,992	72,415	57.45%
44				
45	TOTAL Operation - Admin. & General	4,084,187	4,347,514	6.45%
46	Maintenance			
47	935 Maintenance of General Plant	132,498	117,587	-11.25%
48				
49	TOTAL Administrative & General Expenses	\$4,216,685	\$4,465,101	5.89%
50				
51	TOTAL Operation & Maintenance Expenses	\$30,864,542	\$32,362,143	4.85%

MONTANA TAXES OTHER THAN INCOME

Year: 2008

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	\$430,908	\$436,475	1.29%
2	Secretary of State	373	270	-27.61%
3	Highway Use Tax	293	503	71.67%
4	Montana Consumer Counsel	29,069	54,490	87.45%
5	Montana PSC	88,566	129,332	46.03%
6	Montana Electric	48,711	53,913	10.68%
7	Coal Conversion	286,570	284,381	-0.76%
8	Delaware Franchise	21,493	21,692	0.93%
9	Property Taxes	1,862,384	2,203,252	18.30%
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50	TOTAL MT Taxes Other Than Income	\$2,768,367	\$3,184,308	15.02%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 2008

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Able Field Services	Plant update & repair	\$91,396	\$22,890	25.04%
2					
3	Aerial Contractors Inc.	Contractor services	1,061,920	109,432	10.31%
4					
5	Agri Industries Inc.	Contractor services	314,052	20,462	6.52%
6					
7	Ahern Fire Protection	Fire system installation	319,035	79,901	25.04%
8					
9	All Building Corp	Construction services	677,196	0	0.00%
10					
11	Aptech	Engineering services - L&C Merc Control	118,563	29,694	25.04%
12					
13	Atlantic Insulco Environmental Services	Environmental work	159,290	39,894	25.04%
14					
15	Basin Electric Power Coop	Contract Services	171,325	2,796	1.63%
16					
17	Benco Equipment Co	Vehicle Maintenance	232,299	3,412	1.47%
18					
19	Berger Electric Inc	Boring & pipe installation	82,871	0	0.00%
20					
21	Big K Industries Inc	Contractor services	81,277	15,948	19.62%
22					
23	Black & Veatch	Contractor services	174,788	43,775	25.04%
24					
25	Blue Heron Consulting	Consulting services	2,887,728	378,177	13.10%
26					
27	Broadridge	Contractor services	146,584	1,522	1.04%
28					
29	Bullinger Tree Service	Tree trimming service	261,257	6,579	2.52%
30					
31	Central Trenching Inc	Boring & trenching services	215,247	0	0.00%
32					
33	Chief Construction	Contractor services	482,856	920	0.19%
34					
35	Christensen IR	Investor Relations	87,452	1,040	1.19%
36					
37	Conduit Constructors, LLC	Contractor services	353,561	59,032	16.70%
38					
39	Connecting Point	Computer services & software Mainten.	108,509	7,748	7.14%
40					
41	Corridor Exxon Tire & Auto	Vehicle Maintenance	80,120	0	0.00%
42					
43	Deloitte & Touche	Auditing and consulting services	524,183	35,204	0.00%
44					
45	Dewey & LeBoeuf	Legal Services	1,077,241	13,335	1.24%
46					
47	Energy & Environmental	Contract Services - Environmental	125,412	31,172	24.86%
48					
49	Environmental Energy Services, Inc	Mercury testing	108,522	27,179	25.04%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 2008

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Environmental Services, LTD	Heskett - Unit 2 maintenance	235,662	59,020	25.04%
2					
3	Excavating Specialists	Boring & trenching	83,347	0	0.00%
4					
5	Fischer Contracting	Contract services	356,291	0	0.00%
6					
7	Forrester, Gary	Lobbying & Promotion	93,991	1,155	1.23%
8					
9	Franz Construction Inc	Construction Services	233,769	58,546	25.04%
10					
11	G E Energy Services	Construction Services	104,330	25,695	24.63%
12					
13	Gabe's Construction Co, Inc	Contractor Services	125,919	31,536	25.04%
14					
15	Great Southwestern Construction, Inc.	Tap installation - Tatanka wind farm	106,795	26,746	25.04%
16					
17	Hamilton Spray	Contractor Services - wood pole treatment	197,190	50,698	25.71%
18					
19	Hardy Construction	Construction Services	887,649	20	0.00%
20					
21	HDR Inc	Contractor Services	159,867	40,038	25.04%
22					
23	HessMorganHouse, LLC	Consulting services	81,900	1,047	1.28%
24					
25	Hydrochem Industrial Services	Boiler cleaning	90,509	22,668	25.04%
26					
27	Impact Mechanical	Gas comp. equip install - Glendive unit	125,302	31,381	25.04%
28					
29	Industrial Contractors, Inc.	Construction Services	1,531,199	383,481	25.04%
30					
31	InfraSource Underground	Underground gas line installment	198,966	0	0.00%
32					
33	Intermountain Tree Expert Co	Tree trimming service	125,415	0	0.00%
34					
35	International Business Machines Corp	Contractor services - computer maint.	93,807	7,553	8.05%
36					
37	Itron Inc.	Contract services	2,296,218	103,107	4.49%
38					
39	Jarrett Construction Inc	Storm water imp - Glendive & Miles City	156,884	39,291	25.04%
40		Turbine facilities			
41	Jim's Building Service Inc.	Construction shop - Powell	79,750	0	0.00%
42					
43	Kappel Tree Service LLC	Tree trimming service	142,486	69,686	48.91%
44					
45	La Salle Photography World Wide	Contract Services - Corporate report	84,089	1,143	1.36%
46					
47	Lindquist & Venum, PLLP	Contract Services - Const Big Stone II	127,057	31,821	25.04%
48					
49	Litho of Minnesota, Inc	MDU Resources annual report	115,200	1,196	1.04%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 2008

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	MCM General Contractors, Inc	Boring and pipe installation	361,008	0	0.00%
2					
3	McDermott, Will & Emery LLP	Legal services	158,831	1,893	1.19%
4					
5	Microsoft	Contract services - software maintenance	995,843	23,207	2.33%
6					
7	Midwest ISO	Prelim studies, wind farm & others	286,000	71,625	25.04%
8					
9	New York Life	Consulting services	377,999	15,398	4.07%
10					
11	Northern Improvement Co	Contractor services	143,911	0	0.00%
12					
13	NYSE Market Inc	Financial services	173,624	1,751	1.01%
14					
15	Oakland Construction., Inc	Boring and trenching - cable replacement	194,826	143,305	73.56%
16					
17	Oliver Wyman Corp Risk	Consulting Services	75,000	1,038	1.38%
18	Consulting, Inc.				
19	One Call Locators LTD	Line location services	1,426,402	24,346	1.71%
20					
21	Oracle Corp	Software maintenance	1,035,544	129,552	12.51%
22					
23	Ormat Nevada Inc.	Install energy converter - Glen Ullin	7,052,822	1,766,344	25.04%
24					
25	Osmose Utilities Services Inc	Contract services - overhead line maint.	158,462	64,741	40.86%
26					
27	OTP Big Stone II - Trust Acct	Big Stone II Construction	1,382,676	346,284	25.04%
28					
29	Outdoor Services Inc	Contract Services - meter reading	547,443	11,014	2.01%
30					
31	PA Consulting Services Inc	Consulting services - Big Stone II & WY Gen III	114,895	22,654	19.72%
32					
33	Pole Maintenance Company	Contract services - pole maintenance	255,888	58,477	22.85%
34					
35	Power Generation Service Inc	Replace turbine parts - L&C	103,846	26,008	25.04%
36					
37	Presort Plus Inc	Contract services - mail service	174,054	14,550	8.36%
38					
39	Professional Consultants Inc	Consulting serv - BGB & TGB removal	114,796	28,750	25.04%
40					
41	Progressive Maintenance Co	Custodial services	131,312	19,543	14.88%
42					
43	PSC Industrial Outsourcing Inc.	Boiler maintenance - Heskett	674,219	168,855	25.04%
44					
45	PSC Intermountain	Boiler maintenance - Heskett	165,935	41,558	25.04%
46					
47	Quality Underground Services Inc	Contractor services - gas lines & mains	485,155	0	0.00%
48					
49	Rocky Mountain Contractors, Inc	Contractor services	156,799	0	0.00%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC Year: 2008

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Rocky Mountain Line	Contractor services	134,452	0	0.00%
2					
3	Sargent & Lundy, LLC	Consulting services	484,611	121,368	25.04%
4					
5	Southern Cross Corp	Contract services - leak detection	229,611	0	0.00%
6					
7	Standard & Poor's	Financial services	156,919	3,112	1.98%
8					
9	State-Line Contractors Inc	Construction services	514,398	0	0.00%
10					
11	Strategic Solutions, LLC	Consulting services - CIS project	89,967	11,782	13.10%
12					
13	Structure Group	Market Midwest Annual Base Maint.	84,800	21,030	24.80%
14					
15	Sundog	MDU Resources eSource project	143,081	10,705	7.48%
16					
17	Sutherland Asbill & Brennan LLP	Legal services - Wygen III	106,823	0	0.00%
18					
19	Swanson & Youngdale Inc	Industrial painting contractors	105,005	0	0.00%
20					
21	Thelen LLP	Legal services	371,652	6,723	1.81%
22					
23	Timberline Construction Inc	Construction services	117,263	35,345	30.14%
24					
25	TLT-Babacock Inc	Centrifugal & IVC rebuild - Heskett	165,334	41,407	25.04%
26					
27	Treasury Management Services	Banking Services	306,044	23,843	7.79%
28					
29	UC4 Software, Inc.	Software Maintenance	125,504	16,436	13.10%
30					
31	Ulmer Tree Service	Tree trimming service	187,229	0	0.00%
32					
33	Utilities International, Inc.	Consulting services	966,423	80,429	8.32%
34					
35	Van Horn Media	Advertising	222,779	2,521	1.13%
36					
37	Wanzek Construction Inc	Contractor services	2,315,162	579,821	25.04%
38					
39	Wells Fargo Shareowners Services	Stock transfer agent & ESOP Admin	344,234	4,107	1.19%
40					
41	Wenck	Contractor Services - Billings landfill	110,000	0	0.00%
42					
43	Williams & Associates	Consulting services	90,762	0	0.00%
44					
45	Workforce Services, Inc	Vehicle maintenance	84,067	0	0.00%
46					
47					
48					
49					
50					
51	TOTAL Payments for Services		\$41,979,686	\$5,855,458	13.95%

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

Year: 2008

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	\$58,103	\$7,600	13.08%
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
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33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43	TOTAL Contributions	\$58,103	\$7,600	13.08%

Pension Costs

Year: 2008

1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes		Defined Contribution Plan? No	
3	PROPRIETARY SCHEDULE			
4	PROPRIETARY SCHEDULE			
5				
	Item	Current Year	Last Year	% Change
6	Change in Benefit Obligation			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest Cost			
10	Plan participants' contributions	PROPRIETARY SCHEDULE		
11	Amendments			
12	Actuarial (Gain) Loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year			
16	Change in Plan Assets			
17	Fair value of plan assets at beginning of year			
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution			
21	Plan participants' contributions	PROPRIETARY SCHEDULE		
22	Benefits paid			
23	Fair value of plan assets at end of year			
24	Funded Status			
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost	PROPRIETARY SCHEDULE		
27	Unrecognized net transition obligation			
28	Accrued benefit cost			
29				
30	Weighted-average Assumptions as of Year End			
31	Discount rate	6.25	6.00	4.17%
32	Expected return on plan assets	8.50	8.50	0.00%
33	Rate of compensation increase	4.00	4.15	-3.61%
34				
35	Components of Net Periodic Benefit Costs			
36	Service cost			
37	Interest cost			
38	Expected return on plan assets	PROPRIETARY SCHEDULE		
39	Amortization of prior service cost			
40	Recognized net actuarial gain			
41	Transition amount amortization			
42	Net periodic benefit cost			
43				
44	Montana Intrastate Costs:			
45	Pension Costs	PROPRIETARY SCHEDULE		
46	Pension Costs Capitalized			
47	Accumulated Pension Asset (Liability) at Year End			
48	Number of Company Employees:			
49	Covered by the Plan			
50	Not Covered by the Plan	PROPRIETARY SCHEDULE		
51	Active			
52	Retired			
53	Deferred Vested Terminated			

Other Post Employment Benefits (OPEBS)

	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	6.25	6.00	4.17%
8	Expected return on plan assets	7.50	7.50	0.00%
9	Medical Cost Inflation Rate	6.00	6.00	0.00%
10	Actuarial Cost Method	PROPRIETARY SCHEDULE		
11	Rate of compensation increase	PROPRIETARY SCHEDULE		
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			
18	Benefit obligation at beginning of year	PROPRIETARY SCHEDULE		
19	Service cost			
20	Interest Cost			
21	Plan participants' contributions			
22	Amendments			
23	Actuarial (Gain) Loss			
24	Acquisition			
25	Benefits paid			
26	Benefit obligation at end of year			
27	Change in Plan Assets			
28	Fair value of plan assets at beginning of year	PROPRIETARY SCHEDULE		
29	Actual return on plan assets			
30	Acquisition			
31	Employer contribution			
32	Plan participants' contributions			
33	Benefits paid			
34	Fair value of plan assets at end of year			
35	Funded Status			
36	Unrecognized net actuarial loss	PROPRIETARY SCHEDULE		
37	Unrecognized prior service cost			
38	Unrecognized transition obligation			
39	Accrued benefit cost			
40	Components of Net Periodic Benefit Costs			
41	Service cost	PROPRIETARY SCHEDULE		
42	Interest cost			
43	Expected return on plan assets			
44	Amortization of prior service cost			
45	Recognized net acturial gain			
46	Transition amount amortization			
47	Net periodic benefit cost			
48	Accumulated Post Retirement Benefit Obligation			
49	Amount Funded through VEBA	PROPRIETARY SCHEDULE		
50	Amount Funded through 401(h)			
51	Amount Funded through Other _____			
52	TOTAL			
53	Amount that was tax deductible - VEBA			
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other _____			
56	TOTAL			

Other Post Employment Benefits (OPEBS) Continued

	Item	Current Year	Last Year	% Change
1	Number of Company Employees:			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active	PROPRIETARY SCHEDULE		
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	Montana			
8	Change in Benefit Obligation			
9	Benefit obligation at beginning of year			
10	Service cost	NOT APPLICABLE		
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			
20	Actual return on plan assets	NOT APPLICABLE		
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			
32	Interest cost			
33	Expected return on plan assets	NOT APPLICABLE		
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			
39	Amount Funded through 401(h)			
40	Amount Funded through other _____	NOT APPLICABLE		
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			
52	Not Covered by the Plan	NOT APPLICABLE		
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	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Terry D. Hildestad - President & CEO	\$700,000	\$310,800	\$1,769,119	\$2,779,919	\$3,906,260	-29%
2	John G. Harp - President & CEO of MDU Construction Services Group	400,000	720,000	663,789	1,783,789	1,030,343	73%
3	Vernon A. Raile Executive Vice President, Treasurer and CFO	400,000	115,440	845,692	1,361,132	1,532,480	-11%
4	William Schneider - President & CEO of Knife River Corporation	447,400	0	590,415	1,037,815	1,469,344	-29%
5	Paul K. Sandness General Counsel and Secretary	321,400	71,351	426,057	818,808	1,037,066	-21%

1/ See Page 19a for Total Compensation detail.

Summary Compensation Table for 2008

Name and Principal Position (a)	Year (b)	Salary (\$) (c)	Bonus (\$) (d)	Stock Awards (\$) (e)(1)	Option Awards (\$) (f)(1)	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	2008	700,000	—	860,702	—	310,800	898,941	9,476(3)	2,779,919
	2007	625,000	—	661,821	—	1,250,000	1,362,413	7,026	3,906,260
	2006	562,500	—	376,394	25,084	1,125,000	768,184	6,876	2,864,038
Vernon A. Raile Executive Vice President, Treasurer and CFO	2008	400,000	—	340,306	—	115,440	498,210	7,176(3)	1,361,132
	2007	350,700	—	268,806	—	350,700	555,248	7,026	1,532,480
	2006	318,750	—	161,690	—	318,750	635,356	6,876	1,441,422
John G. Harp President and CEO of MDU Construction Services Group, Inc.	2008	400,000	—	301,785	—	720,000(4)	338,774(6)	23,230(7)	1,783,789
	2007	341,000	—	277,929	—	341,000	47,334(6)	23,080(7)	1,030,343
	2006	310,000	—	150,566	—	810,000(5)	324,976(6)	31,323(7)	1,626,865
William E. Schneider ... President and CEO of Knife River Corporation	2008	447,400	—	400,638	—	—	180,801	8,976(3)	1,037,815
	2007	422,000	—	383,191	—	206,780	450,347	7,026	1,469,344
	2006	392,000	—	248,217	20,729	392,000	609,916	6,876	1,669,738
Paul K. Sandness General Counsel and Secretary	2008	321,400	—	246,228	—	71,351	170,403	9,426(3)	818,808
	2007	—	—	—	—	—	—	—	—
	2006	—	—	—	—	—	—	—	—

- (1) Amounts in these columns represent the dollar amount recognized for financial statement reporting purposes for the 2008, 2007, and 2006 fiscal years for restricted stock awards, performance share awards, and stock option awards granted in 2008 and prior years. These amounts reflect our accounting expense for these awards and do not correspond to the actual value that will be recognized by the named executive officers. Assumptions used to determine the amounts in these columns are the same as used in the calculation of compensation expense for our audited financial statements, except for the effect of estimated forfeitures. Statement of Financial Accounting Standards No. 123 (revised), "Share-Based Payment" requires us to estimate forfeitures when awards are granted and reduce estimated compensation expense accordingly. These columns were prepared assuming none of the awards will be forfeited. However, for both these columns and our audited financial statements, compensation expense is adjusted for actual forfeitures.

The grant date fair value of restricted stock awards was based on the market price of our stock on the grant date.

The grant date fair value for the performance shares granted in 2008 was determined by Monte Carlo simulation using a blended volatility term structure in the range of 21.54% to 22.97% comprised of 50% historical volatility and 50% implied volatility and a risk-free interest rate term structure in the range of 1.87% to 2.23% based on the U.S. Treasury security rates in effect as of the grant date. In addition, the mean overall simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was \$1.64 per target share.

The grant date fair value for the performance shares granted in 2007 was determined by Monte Carlo simulation using a blended volatility term structure in the range of 18.17% to 18.73% comprised of 50% historical volatility and 50% implied volatility and a risk-free interest rate term structure in the range of 4.75% to 5.21% based on the U.S. Treasury security rates in effect as of the grant date. In addition, the mean overall simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was \$1.25 per target share.

The grant date fair value for the performance shares granted in 2006 was determined by Monte Carlo simulation using a blended volatility term structure in the range of 17.65% to 18.79% comprised of 50% historical volatility and 50% implied volatility and a risk-free interest rate term structure in the range of 4.66% to 4.79% based on the U.S. Treasury security rates in effect as of the grant date. In addition, the mean overall simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was \$1.37 per target share.

The grant date fair value for the performance share awards granted in 2005 and 2004 were equal to the market value of our common stock on the grant date.

The fair value of stock options was estimated on the grant date using the Black-Scholes option-pricing model. The fair value of the options granted and the underlying assumptions were as follows:

Fair value of options at grant date	\$3.22
Risk-free interest rate	5.18%
Expected price volatility	25.94%
Expected dividend yield	3.53%
Expected life in years	7
Date of Grant	February 14, 2001

For additional information about these stock awards and option awards, refer to Note 14 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2008.

- (2) Amounts shown represent the change in the actuarial present value for years ending December 31, 2006, 2007, and 2008 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, 2006, 2007, and 2008 as follows:

Name	Accumulated Pension Change			Above Market Earnings		
	12/31/2006 (\$)	12/31/2007 (\$)	12/31/2008 (\$)	12/31/2006 (\$)	12/31/2007 (\$)	12/31/2008 (\$)
Terry D. Hildestad	752,265	1,336,815	883,351	15,919	25,598	15,590
Vernon A. Raile	608,295	508,987	469,755	27,061	46,261	28,455
John G. Harp	239,228	38,498	331,558	—	—	—
Additional Retirement (John G. Harp)*	85,748	8,836	7,216	—	—	—
William E. Schneider	593,820	411,123	155,816	16,096	39,224	24,985
Paul K. Sandness	—	—	170,403	—	—	—

*See footnote 6.

- (3) Includes company contributions to the 401(k) account, payment of a life insurance premium, and, except for Mr. Raile, matching contributions to charitable organizations.
- (4) Includes one-time incentive payment of \$200,000 in addition to his executive incentive compensation plan payment.
- (5) Includes one-time incentive payment of \$500,000 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:

	2006	2007	2008
Change in present value of additional years of service for pension plan ..	\$77,447	\$6,033	\$3,570
Change in present value of additional years of service for excess SISP ..	8,301	2,803	3,646
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 2008 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 2006, 2007, and 2008. 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 2008 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 2008 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) account, 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 2008

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options (#) (j)	Exercise or Base Price of Option Awards (\$/Sh) (k)	Grant Date Fair Value of Stock and Option Awards (\$) (l)
		Threshold (\$) (c)	Target (\$) (d)	Maximum (\$) (e)	Threshold (\$) (f)	Target (\$) (g)	Maximum (\$) (h)				
Terry D. Hildestad	2/14/08(1)	175,000	700,000	1,400,000	—	—	—	—	—	—	1,200,485
	2/14/08(2)	—	—	—	3,909	39,091	78,182	—	—	—	
Vernon A. Raile	2/14/08(1)	65,000	260,000	520,000	—	—	—	—	—	—	411,575
	2/14/08(2)	—	—	—	1,340	13,402	26,804	—	—	—	
John G. Harp	2/14/08(1)	65,000	260,000	520,000	—	—	—	—	—	—	411,575
	2/14/08(2)	—	—	—	1,340	13,402	26,804	—	—	—	
	2/14/08(3)	—	200,000	—	—	—	—	—	—	—	
William E. Schneider . .	2/14/08(1)	72,703	290,810	581,620	—	—	—	—	—	—	460,374
	2/14/08(2)	—	—	—	1,499	14,991	29,982	—	—	—	
Paul K. Sandness	2/14/08(4)	40,175	160,700	321,400	—	—	—	—	—	—	275,592
	2/14/08(2)	—	—	—	897	8,974	17,948	—	—	—	

- (1) Annual incentive for 2008 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.
- (2) Performance shares for the 2008-2010 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.
- (3) Mr. Harp's 2008 additional annual incentive opportunity for 2008.
- (4) Annual incentive for 2008 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

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

Incentive Awards

Annual Incentive

On February 12, 2008, the compensation committee recommended the 2008 annual incentive award opportunities for our named executive officers, and the board approved these opportunities at its meeting on February 14, 2008. These award opportunities are reflected in the Grants of Plan-Based Awards table at grant on February 14, 2008 in columns (c), (d) and (e) and in the Summary Compensation Table as earned with respect to 2008 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, 2008, 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 our Executive Incentive Compensation Plan, which includes Mr. Sandness, 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, Raile, and Sandness, 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 and Harp, 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.

For 2008, the compensation committee weighted the goals for annual return on invested capital compared to planned results and allocated earnings per share compared to planned results each at 50%.

We limit the after-tax 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 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 and Schneider, and at the corporate level for corporate executives, which include Messrs. Hildestad, Raile, and Sandness.

The award opportunities available to each named executive officer were:

<u>2008 earnings per share results as a % of 2008 target</u>	<u>Corresponding payment of annual incentive target based on earnings per share</u>
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

2008 return on invested capital results as a % of 2008 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 the annual incentive that Mr. Harp earned under our Long-Term Performance Based Incentive Plan, Mr. Harp earned an additional \$200,000 incentive payment. The performance target for this additional \$200,000 was MDU Construction Services Group, Inc.'s attainment of incremental after-tax earnings necessary to achieve return on invested capital results that were at least 200 basis points above the weighted cost of capital. Mr. Harp earned the additional \$200,000 incentive payment because MDU Construction Services Group, Inc.'s 2008 return on invested capital exceeded its weighted average cost of capital by more than 200 basis points.

Long-Term Incentive

On February 12, 2008, 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 14, 2008. These grants are reflected in columns (f), (g), (h), and (i) of the Grants of Plan-Based Awards table.

From 0% to 200% of the target grant will be paid out in February 2011, depending on our 2008-2010 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 14, 2008 Grant
100 th	200%
75 th	150%
50 th	100%
40 th	10%
Less than 40 th	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 2011 at the same time as the performance awards are paid.

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 2008.

Name	Salary (\$)	Total Compensation (\$)	Salary as % of Total Compensation
Terry D. Hildestad	700,000	2,779,919	25.2
Vernon A. Raile	400,000	1,361,132	29.4
John G. Harp	400,000	1,783,789	22.4
William E. Schneider	447,400	1,037,815	43.1
Paul K. Sandness	321,400	818,808	39.3

Outstanding Equity Awards at Fiscal Year-End 2008

Name (a)	Option Awards					Stock Awards			
	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price (\$) (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)(1,2)	Market Value of Shares or Units of Stock That Have Not Vested (\$) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)(1,3)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested (\$) (j)(4)
Terry D. Hildestad .	—	—	—	—	—	3,712	80,105	168,247	3,630,770
Vernon A. Raile ..	—	—	—	—	—	1,114	24,040	64,361	1,388,910
John G. Harp	—	—	—	—	—	—	—	57,238	1,235,196
William E. Schneider	—	—	—	—	—	2,970	64,093	75,505	1,629,398
Paul K. Sandness ..	—	—	—	—	—	—	—	46,146	995,831

- (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 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 three-year performance cycles: 2001-2003, 2004-2006, and 2007-2009. Non-preferential dividends are paid on these shares.

(3)

Named Executive Officer	Award	Shares	End of Performance Period
Terry D. Hildestad	2006	23,883	12/31/08
	2007	66,182	12/31/09
	2008	78,182	12/31/10
Vernon A. Raile	2006	12,429	12/31/08
	2007	25,128	12/31/09
	2008	26,804	12/31/10
John G. Harp	2006	10,072	12/31/08
	2007	20,362	12/31/09
	2008	26,804	12/31/10
William E. Schneider	2006	15,285	12/31/08
	2007	30,238	12/31/09
	2008	29,982	12/31/10
Paul K. Sandness	2006	9,748	12/31/08
	2007	18,450	12/31/09
	2008	17,948	12/31/10

Shares for the 2006 award are shown at the target level (100%) based on results for the 2006-2008 performance cycle above threshold but below target.

Shares for the 2007 award are shown at the maximum level (200%) based on results for the first two years of the 2007-2009 performance cycle above target.

Shares for the 2008 award are shown at the maximum level (200%) based on results for the first year of the 2008-2010 performance cycle above target.

- (4) Value based on the number of performance shares reflected in column (i) multiplied by \$21.58, the year-end closing price for 2008.

Option Exercises and Stock Vested during 2008

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	—	—	23,711	669,523
Vernon A. Raile	—	—	7,738	218,496
John G. Harp	—	—	13,351	376,990
William E. Schneider	—	—	16,022	452,410
Paul K. Sandness	—	—	14,419	407,147

- (1) Adjusted for the 3-for-2 stock split effective July 26, 2006.
- (2) Reflects performance shares for the 2005-2007 performance period that vested on February 14, 2008.
- (3) Reflects the value of performance shares based on our stock price of \$26.66 on February 14, 2008, and the dividend equivalents that were paid on the vested shares.

Pension Benefits for 2008

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	1,192,875	—
	SISP I(1)	26	1,327,047	—
	SISP II(2)	26	2,191,152	—
	SISP Excess	26	639,338	—
Vernon A. Raile	Pension Plan	29	952,396	—
	SISP I(1)	26	814,251	—
	SISP II(2)	26	1,363,592	—
	SISP Excess	26	32,729	—
John G. Harp	Pension Plan	4	120,481	—
	SISP I(1)	3	—	—
	SISP II(2)	3	1,106,368	—
	SISP Excess	3	20,090	—
	Harp Additional Retirement Benefit	3	101,800	—
William E. Schneider	Pension Plan	15	546,165	—
	SISP I(1)	14	974,098	—
	SISP II(2)	14	841,584	—
	SISP Excess	14	97,335	—
Paul K. Sandness	Pension Plan	28	740,641	—
	SISP I(1)	18	232,690	—
	SISP II(2)	18	552,315	—
	SISP Excess	18	83,744	—

(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, 2008, calculated using a 6.25% 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. Hildestad, Harp, and Sandness and age 62 for Mr. Schneider. These are the earliest ages at which the executives could begin receiving unreduced benefits. Retirement on December 31, 2008, was assumed for Mr. Raile, who is currently age 64. The amounts shown for the SISP I and SISP II were determined using a 6.25% 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, Harp, and Sandness 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. Pension benefits under our 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; bonuses 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 the pension plans is 35. Pension plan benefits are not reduced for social security benefits.

To receive unreduced retirement benefits under our 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. Mr. Raile is currently eligible for unreduced retirement benefits under our pension plan. Participants whose employment terminates between the ages of 55 and 60, with 5 years of service, in our 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 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. Hildestad 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. Sandness 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 2008, the maximum annual benefit payable under the pension plans was \$185,000 and the maximum amount of compensation that could be recognized when determining benefits was \$230,000.

Supplemental Income Security Plan

We also offer key managers and executives, including all of our named executive officers, benefits under our non-qualified 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 supplement 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.

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

Regular SISP Benefits and Death Benefits

Regular SISP benefits and death benefits are determined by reference to a schedule. Our compensation committee, after receiving recommendations from our chief executive officer, determines the level at which participants are placed in the schedule. A participant's placement is generally, but not always, determined by reference to the participant's annual base salary.

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."

We amended the SISP in 2005 to address changes in applicable tax laws resulting from the enactment of section 409A of the Internal Revenue Code. As amended, 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. We refer to these benefits 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. Distribution of SISP II benefits generally is deferred for six months and the benefits are paid over 173 months. 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 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 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 benefit. Alternatively, participants can elect to receive both a regular SISP benefit and a SISP death benefit. A similar, one-time election may be made with respect to SISP II benefits, provided the election is made sufficiently in advance of the date SISP retirement benefits start.

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.

SISP death benefits become fully vested if the participant dies while actively employed. Otherwise, the SISP death benefits are subject to the same vesting schedule 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 our qualified pension plan 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. With the exception of Mr. Harp, each of the named executive officers would be entitled to the excess SISP benefits 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 up 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 benefits are 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 the pension plan, excess SISP, and the SISP if he did not resign or retire before January 2, 2008, and if he had acceptable successors in place prior to his departure. 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, 2008, 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."

Nonqualified Deferred Compensation for 2008

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	—	—	54,643	—	783,618
Vernon A. Raile	—	—	99,027	—	1,416,234
John G. Harp	—	—	—	—	—
William E. Schneider	—	—	87,572	—	1,255,849(1)
Paul K. Sandness	—	—	—	—	—

(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 2008, commencing January 1, 2008, was 7.25% or the prime rate as of December 31, 2007. 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—Potential Payments upon Termination or Change of Control—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, 2008. All of the payments and benefits described below would be provided by the company or its subsidiaries.

The tables exclude base salary, 2008 annual incentives, stock awards the named executive officers earned due to employment through December 31, 2008, 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 2008 table. See the Pension Benefits for 2008 table and the Nonqualified Deferred Compensation for 2008 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 all 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 6.25%. 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, 2008.

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 of the named executive officers' outstanding unvested stock options and 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 public announcement that another entity will acquire 20% or more of our voting stock
- commencement of a tender or exchange offer the consummation of which would result in the acquisition of 30% or more of our voting stock
- the announcement of a transaction that would constitute a change in control under Item 6(e) of Schedule 14A under the Securities Exchange Act of 1934, as amended
- a proposed change in a majority of our board of directors during any two consecutive years, unless the election or nomination of each new director was approved by a vote of at least two-thirds of the directors then still in office who were members of the board at the beginning of the period or
- any other event deemed by a majority of the compensation committee of our board to constitute a change of control.

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 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. If a termination of employment occurs for a reason other than cause during the third year of

the performance period, the executive receives the full amount of any performance shares earned. Accordingly, if a December 31, 2008 termination is assumed, the 2008-2010 performance share awards would be forfeited, the 2007-2009 performance share awards would be reduced by one-third, and the 2006-2008 performance share awards would be earned. The number of performance shares earned depends on actual performance through the full performance period. As actual performance for the 2006-2008 performance share awards has been determined, the amounts for these awards in the event of a non-change of control termination were reflected based on actual performance which resulted in vesting of 82% of the original award. In the event of a change of control, these awards would be valued based on the vesting of the target award. To illustrate the potential vesting that could occur under the 2007-2009 performance share awards, we assumed target performance would be achieved. 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, 2008 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, 2008.

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.

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, 2008, 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 Sandness would be entitled to over the three-year employment

period would be \$1,250,000, \$350,700, \$1,000,000, \$392,000, and \$309,000, 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, 2008.

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.

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						2,100,000	
Short-term Incentive(1)						5,000,000	
2006-2008 Performance Shares . . .	455,590	455,590		455,590	455,590	555,600	555,600
2007-2009 Performance Shares . . .	501,667	501,667		501,667	501,667	752,489	752,489
2008-2010 Performance Shares . . .						867,038	867,038
Restricted Stock						80,105	80,105
Benefits and Perquisites:							
Regular SISP(2)	3,518,199	3,518,199			3,518,199	3,518,199	
Excess SISP(3)	776,483	776,483			776,483	776,483	
SISP Death Benefits(4)				10,014,300			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(5)						1,610,378	
Total	5,251,939	5,251,939		10,971,557	5,251,939	15,310,292	2,255,232

- (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, 2008, 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 2008 or (2) the highest annual incentive paid in 2006, 2007, and 2008.
- (2) Represents the present value of Mr. Hildestad's vested regular SISP benefit as of December 31, 2008, which was \$42,710 per month for 15 years, commencing at age 65. Present value was determined using a 6.25% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2008 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. The terms of the excess SISP benefit are described following the Pension Benefits for 2008 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 6.25% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2008 table.
- (5) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

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						1,200,000	
Short-term Incentive(1)						1,402,800	
2006-2008 Performance Shares . . .	237,101	237,101		237,101	237,101	289,141	289,141
2007-2009 Performance Shares . . .	190,470	190,470		190,470	190,470	285,705	285,705
2008-2010 Performance Shares . . .						297,256	297,256
Restricted Stock						24,040	24,040
Benefits and Perquisites:							
Regular SISP(2)	2,177,843	2,177,843			2,177,843	2,177,843	
Excess SISP(3)	32,730	32,730			32,730	32,730	
SISP Death Benefits(4)				4,578,066			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(5)						609,787	
Total	2,638,144	2,638,144		5,005,637	2,638,144	6,369,302	896,142

- (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, 2008, 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 2008 or (2) the highest annual incentive paid in 2006, 2007, and 2008.
- (2) Represents the present value of Mr. Raile's vested regular SISP benefit as of December 31, 2008, which was \$19,525 per month for 15 years, commencing at age 65. Present value was determined using a 6.25% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2008 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 all excess SISP benefits Mr. Raile would be entitled to upon termination of employment under the SISP. The terms of the excess SISP benefit are described following the Pension Benefits for 2008 table. The three additional years of employment assumed for purposes of calculating the additional retirement plan payment under Mr. Raile'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 \$39,050 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 6.25% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2008 table.
- (5) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

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						1,200,000	
Short-term Incentive(1)						4,000,000	
2006-2008 Performance Shares . . .	192,132	192,132		192,132	192,132	234,309	234,309
2007-2009 Performance Shares . . .	154,336	154,336		154,336	154,336	231,516	231,516
2008-2010 Performance Shares . . .						297,256	297,256
Restricted Stock							
Benefits and Perquisites:							
Incremental Pension(2)	225,076	225,076			225,076	225,076	
Regular SISP					328,390(3)	774,456(4)	
Excess SISP							
SISP Death Benefits(5)				3,777,344			
Disability Benefits						405,708	
Outplacement Services						50,000	
280G Tax(6)						1,280,693	
Total	571,544	571,544		4,123,812	899,934	8,699,014	763,081

- (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, 2008, 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 2008 or (2) the highest annual incentive paid in 2006, 2007, and 2008.
- (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 2008 table.
- (3) Represents the present value of the additional SISP retirement benefit due to an additional two years vesting under our SISP. The terms of the excess SISP benefit are described following the Pension Benefits for 2008 table. Present value was determined using a 6.25% discount rate.
- (4) Represents the payment that would be made under Mr. Harp's change of control agreement based on the increase in the actuarial present value of his regular SISP benefit that would result if he continued employment for an additional three years. 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 2008 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 6.25% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2008 table.
- (6) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

William E. Schneider

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination (\$)	Not for Cause Termination (4)	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)						1,568,000	
2006-2008 Performance Shares . . .	291,583	291,583		291,583	291,583	355,581	355,581
2007-2009 Performance Shares . . .	229,196	229,196		229,196	229,196	343,806	343,806
2008-2010 Performance Shares . . .						332,500	332,500
Restricted Stock						64,093	64,093
Benefits and Perquisites:							
Regular SISP(2)	1,815,682	1,815,682			1,815,682	1,815,682	
Excess SISP(3)	127,419	127,419			127,419	127,419	
SISP Death Benefits(4)				4,578,066			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(5)						645,061	
Total	2,463,880	2,463,880		5,098,845	2,463,880	6,644,342	1,095,980

- (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, 2008, 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 2008 or (2) the highest annual incentive paid in 2006, 2007, and 2008.
- (2) Represents the present value of Mr. Schneider's vested regular SISP benefit as of December 31, 2008, which was \$19,525 per month for 15 years, commencing at age 65. Present value was determined using a 6.25% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2008 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. The terms of the excess SISP benefit are described following the Pension Benefits for 2008 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 \$39,050 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 6.25% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2008 table.
- (5) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

Paul K. Sandness

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						964,200	
Short-term Incentive(1)						1,236,000	
2006-2008 Performance Shares . . .	185,944	185,944		185,944	185,944	226,772	226,772
2007-2009 Performance Shares . . .	139,851	139,851		139,851	139,851	209,777	209,777
2008-2010 Performance Shares . . .						199,043	199,043
Restricted Stock							
Benefits and Perquisites:							
Regular SISP(2)	785,005	785,005			785,005	785,005	
Excess SISP(3)	147,969	147,969			147,969	162,224	
SISP Death Benefits(4)				2,847,663			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(5)						537,557	
Total	1,258,769	1,258,769		3,173,458	1,258,769	4,370,578	635,592

- (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, 2008, 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 2008 or (2) the highest annual incentive paid in 2006, 2007, and 2008.
- (2) Represents the present value of Mr. Sandness' vested regular SISP benefit as of December 31, 2008, which was \$12,145 per month for 15 years, commencing at age 65. Present value was determined using a 6.25% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2008 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Sandness' 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. Sandness would be entitled to upon termination of employment under the SISP. The terms of the excess SISP benefit are described following the Pension Benefits for 2008 table.
- (4) Represents the present value of 180 monthly payments of \$24,290 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 6.25% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2008 table.
- (5) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

Director Compensation for 2008

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	54,500	115,518	—(3)	—	—	276	170,294
Karen B. Fagg	54,000	115,518	—	—	—	276	169,794
A. Bart Holaday(4)	9,500	—	—	—	—	46	9,546
Dennis W. Johnson	64,000(5)	115,518	—	—	—	276	179,794
Thomas C. Knudson(4) ...	9,500	—	—	—	—	46	9,546
Richard H. Lewis	57,000	115,518	—	—	—	276	172,794
Patricia L. Moss	49,500(6)	115,518	—	—	—	276	165,294
John L. Olson	62,000	115,518	—(7)	—	—	276	177,794
Harry J. Pearce	80,007	165,511(8)	—(9)	—	—	276	245,794
Sister Thomas Welder	48,000	115,518	—	—	—	276	163,794
John K. Wilson	54,000(10)	115,518	—	—	—	276	169,794

- (1) Valued based on \$28.523, the purchase price of the stock on the date of grant, April 28, 2008, which is the grant date fair value, except for Mr. Pearce. See footnote 8 for Mr. Pearce.
- (2) Group life insurance premiums.
- (3) Mr. Everist had 23,624 stock options outstanding as of December 31, 2008.
- (4) Appointed to the board effective November 1, 2008.
- (5) Includes \$63,979 that Mr. Johnson received in our common stock in lieu of cash.
- (6) Includes \$49,489 that Ms. Moss received in our common stock in lieu of cash.
- (7) Mr. Olson had 18,562 stock options outstanding as of December 31, 2008.
- (8) Includes (a) \$115,518 for the April 28, 2008 stock grant based on \$28.523, the purchase price of the stock, and (b) \$49,993 of stock paid on December 10, 2008 based on a purchase price of \$20.97, as part of Mr. Pearce's retainer as chairman of the board.
- (9) Mr. Pearce had 13,500 stock options outstanding as of December 31, 2008.
- (10) Includes \$29,987 that Mr. Wilson received in our common stock in lieu of cash.

BALANCE SHEET

Year: 2008

	Account Number & Title	Last Year	This Year	% Change
1	Assets and Other Debits			
2	Utility Plant			
3	101 Electric Plant in Service	\$674,247,658	\$736,893,792	9.29%
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	54,075,641	50,812,067	-6.04%
10	108 (Less) Accumulated Depreciation	(388,933,401)	(403,399,367)	3.72%
11	111 (Less) Accumulated Amortization	(4,336,645)	(4,705,268)	8.50%
12	114 Electric Plant Acquisition Adjustments	10,387,643	10,387,642	0.00%
13	115 (Less) Accum. Amort. Electric Plant Acq. Adj.	(8,820,337)	(9,234,596)	4.70%
14	120 Nuclear Fuel (Net)			
15	Other Utility Plant	348,968,301	380,968,710	9.17%
16	Accum. Depr. and Amort. - Other Util. Plant	(196,857,130)	(206,061,656)	4.68%
17	TOTAL Utility Plant	\$488,731,730	\$555,661,324	13.69%
18	Other Property & Investments			
19	121 Nonutility Property	\$3,117,373	\$3,707,024	18.91%
20	122 (Less) Accum. Depr. & Amort. of Nonutil. Prop.	(1,013,133)	(1,117,112)	10.26%
21	123 Investments in Associated Companies			
22	123.1 Investments in Subsidiary Companies	2,284,551,173	2,478,164,341	8.47%
23	124 Other Investments	40,972,687	35,032,098	-14.50%
24	125 Sinking Funds			
25	TOTAL Other Property & Investments	\$2,327,628,100	\$2,515,786,351	8.08%
26	Current & Accrued Assets			
27	131 Cash	\$2,633,013	\$181,115	-93.12%
28	132-134 Special Deposits	1,200	1,200	0.00%
29	135 Working Funds	163,690	113,921	-30.40%
30	136 Temporary Cash Investments	422,455	1,938,468	358.86%
31	141 Notes Receivable			
32	142 Customer Accounts Receivable	27,981,262	29,930,415	6.97%
33	143 Other Accounts Receivable	3,357,347	2,394,649	-28.67%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(230,059)	(285,809)	24.23%
35	145 Notes Receivable - Associated Companies		57,000,000	
36	146 Accounts Receivable - Associated Companies	30,629,676	26,427,125	-13.72%
37	151 Fuel Stock	4,055,099	4,099,005	1.08%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals and Extracted Products			
40	154 Plant Materials and Operating Supplies	9,128,932	10,225,093	12.01%
41	155 Merchandise	1,470,096	1,742,091	18.50%
42	156 Other Material & Supplies			
43	163 Stores Expense Undistributed			
44	164.1 Gas Stored Underground - Current	18,158,827	8,529,714	-53.03%
45	165 Prepayments	4,425,641	4,865,549	9.94%
46	166 Advances for Gas Explor., Devl. & Production			
47	171 Interest & Dividends Receivable			
48	172 Rents Receivable			
49	173 Accrued Utility Revenues	39,762,227	46,729,484	17.52%
50	174 Miscellaneous Current & Accrued Assets	184,014	2,560	-98.61%
51	TOTAL Current & Accrued Assets	\$142,143,420	\$193,894,580	36.41%

BALANCE SHEET

Year: 2008

	Account Number & Title	Last Year	This Year	% Change
1	Assets and Other Debits (cont.)			
2				
3	Deferred Debits			
4				
5	181 Unamortized Debt Expense	\$893,195	\$1,191,582	33.41%
6	182.1 Extraordinary Property Losses			
7	182.2 Unrecovered Plant & Regulatory Study Costs			
8	182.3 Other Regulatory Assets	20,474,249	88,196,422	330.77%
9	183 Prelim. Electric Survey & Investigation Chrg.	766,627	579,901	-24.36%
10	183.1 Prelim. Nat. Gas Survey & Investigation Chrg.	17,318	0	-100.00%
11	183.2 Other Prelim. Nat. Gas Survey & Invtg. Chrgs.	0	2,084	100.00%
12	184 Clearing Accounts	(49,436)	(191,726)	287.83%
13	185 Temporary Facilities			
14	186 Miscellaneous Deferred Debits	30,878,709	26,229,986	-15.05%
15	187 Deferred Losses from Disposition of Util. Plant			
16	188 Research, Devel. & Demonstration Expend.			
17	189 Unamortized Loss on Reacquired Debt	10,604,809	9,990,648	-5.79%
18	190 Accumulated Deferred Income Taxes	37,651,678	60,304,833	60.17%
19	191 Unrecovered Purchased Gas Costs	3,474,582	24,225,488	597.22%
20	192.1 Unrecovered Incremental Gas Costs			
21	192.2 Unrecovered Incremental Surcharges			
22	TOTAL Deferred Debits	\$104,711,731	\$210,529,218	101.06%
23				
24	TOTAL ASSETS & OTHER DEBITS	\$3,063,214,981	\$3,475,871,473	13.47%
	Account Number & Title	Last Year	This Year	% Change
25	Liabilities and Other Credits			
26				
27	Proprietary Capital			
28				
29	201 Common Stock Issued	\$182,946,528	\$184,208,283	0.69%
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	916,218,614	941,909,202	2.80%
34	211 Miscellaneous Paid-In Capital			
35	213 (Less) Discount on Capital Stock			
36	214 (Less) Capital Stock Expense	(3,412,569)	(3,610,416)	5.80%
37	216 Appropriated Retained Earnings	303,634,911	436,608,753	43.79%
38	216.1 Unappropriated Retained Earnings	1,129,950,735	1,180,220,338	4.45%
39	217 (Less) Reacquired Capital Stock	(3,625,813)	(3,625,813)	0.00%
40	219 Accumulated Other Comprehensive Income	(9,393,173)	10,365,311	210.35%
41	TOTAL Proprietary Capital	\$2,531,319,233	\$2,761,075,658	9.08%
42				
43	Long Term Debt			
44				
45	221 Bonds	\$150,500,000	\$235,500,000	56.48%
46	222 (Less) Reacquired Bonds			
47	223 Advances from Associated Companies			
48	224 Other Long Term Debt	61,800,000	80,708,867	30.60%
49	225 Unamortized Premium on Long Term Debt			
50	226 (Less) Unamort. Discount on Long Term Debt-Dr.	(2,417)	(1,837)	-24.00%
51	TOTAL Long Term Debt	\$212,297,583	\$316,207,030	48.95%

BALANCE SHEET

Year: 2008

	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	\$1,821,121	\$1,582,142	-13.12%
9	228.3 Accumulated Provision for Pensions & Benefits	45,052,837	59,371,415	31.78%
10	228.4 Accumulated Misc. Operating Provisions			
11	229 Accumulated Provision for Rate Refunds			
12	230 Asset Retirement Obligations	2,518,372	2,691,414	6.87%
13	TOTAL Other Noncurrent Liabilities	\$49,392,330	\$63,644,971	28.86%
14				
15	Current & Accrued Liabilities			
16				
17	231 Notes Payable	\$0	\$0	0.00%
18	232 Accounts Payable	49,239,911	33,220,974	-32.53%
19	233 Notes Payable to Associated Companies			
20	234 Accounts Payable to Associated Companies	9,391,348	7,119,598	-24.19%
21	235 Customer Deposits	2,340,670	2,408,988	2.92%
22	236 Taxes Accrued	19,382,784	(840,838)	-104.34%
23	237 Interest Accrued	2,664,504	4,206,271	57.86%
24	238 Dividends Declared	26,619,224	28,639,606	7.59%
25	239 Matured Long Term Debt			
26	240 Matured Interest			
27	241 Tax Collections Payable	1,525,151	1,578,001	3.47%
28	242 Miscellaneous Current & Accrued Liabilities	25,405,080	25,765,992	1.42%
29	243 Obligations Under Capital Leases - Current			
30	TOTAL Current & Accrued Liabilities	\$136,568,672	\$102,098,592	-25.24%
31				
32	Deferred Credits			
33				
34	252 Customer Advances for Construction	\$3,342,874	\$5,289,755	58.24%
35	253 Other Deferred Credits	46,514,581	101,962,554	119.21%
36	254 Other Regulatory Liabilities	10,023,560	9,003,884	-10.17%
37	255 Accumulated Deferred Investment Tax Credits	609,529	361,334	-40.72%
38	256 Deferred Gains from Disposition Of Util. Plant			
39	257 Unamortized Gain on Reacquired Debt			
40	281-283 Accumulated Deferred Income Taxes	73,146,619	116,227,695	58.90%
41	TOTAL Deferred Credits	\$133,637,163	\$232,845,222	74.24%
42				
43	TOTAL LIABILITIES & OTHER CREDITS	\$3,063,214,981	\$3,475,871,473	13.47%

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) 12/31/2008	Year/Period of Report 2008/Q4
MDU Resources Group, Inc.			
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 16. The statements also include the ownership interests in the assets, liabilities and expenses of two 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 investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by \$1,343,759,873; current and accrued assets would increase by \$1,078,397,064; deferred debits would increase by \$689,816,306; long-term debt would increase by \$1,252,428,624; other noncurrent liabilities and current and accrued liabilities would increase by \$801,731,078; deferred credits would increase by \$1,057,813,541 as of December 31, 2008. Furthermore, operating revenues would increase by \$4,418,448,695 and operating expenses, excluding income taxes, would increase by \$3,952,145,625 for the twelve months ended December 31, 2008. In addition, net cash provided by operating activities would increase by \$738,926,000; net cash used in investing activities would increase by \$1,050,810,000; net cash provided by financing activities would increase by \$259,399,000; the effect of exchange rate changes on cash would decrease by \$635,000; and the net change in cash and cash equivalents would be a decrease of \$53,121,000 for the twelve months ended December 31, 2008. Reporting its subsidiary investment 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 SFAS No. 71. SFAS No. 71 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

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being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

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

Cash and cash equivalents

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

Allowance for doubtful accounts

The Company's allowance for doubtful accounts as of December 31, 2008 and 2007, was \$13.7 million and \$14.6 million, respectively.

Natural gas in storage

Natural gas in storage for the Company's regulated operations is generally carried at 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 \$27.6 million and \$28.8 million at December 31, 2008 and 2007, 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 \$43.4 million and \$43.0 million at December 31, 2008 and 2007, respectively.

Inventories

Inventories, other than natural gas in storage for the Company's regulated operations, consisted primarily of aggregates held for resale of \$89.1 million and \$102.2 million, materials and supplies of \$92.4 million and \$56.0 million, and other inventories of \$52.4 million and \$42.3 million, as of December 31, 2008 and 2007, 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, upon the adoption of SFAS No. 159, 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. Prior to the adoption of SFAS No. 159, the Company's fixed-income and equity securities were accounted for as available-for-sale investments in accordance with SFAS No. 115. In accordance with SFAS No. 115, these investments 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 in accordance with SFAS No. 115. For more information, see Notes 8 and 17 and comprehensive income 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 \$9.0 million, \$7.1 million and \$5.8 million

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in 2008, 2007 and 2006, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves.

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

	2008	2007	Weighted Average Depreciable Life in Years
<i>(Dollars in thousands, as applicable)</i>			
Regulated:			
Electric:			
Generation	\$ 408,851	\$ 371,557	63
Distribution	219,501	206,967	36
Transmission	142,081	133,973	44
Other	78,292	72,208	12
Natural gas distribution:			
Distribution	1,260,651	828,458	38
Other	168,836	119,988	17
Pipeline and energy services:			
Transmission	322,276	297,312	53
Gathering	41,825	41,233	19
Storage	32,592	32,082	52
Other	31,925	32,832	27
Nonregulated:			
Construction services:			
Land	4,526	4,513	---
Buildings and improvements	12,913	11,987	23
Machinery, vehicles and equipment	84,042	76,937	6
Other	9,820	8,498	4
Pipeline and energy services:			
Gathering	201,323	187,555	17
Other	10,980	9,698	10
Natural gas and oil production:			
Natural gas and oil properties	2,443,946	1,892,757	*
Other	33,456	31,142	9
Construction materials and contracting:			
Land	127,279	115,935	---
Buildings and improvements	68,356	94,598	20
Machinery, vehicles and equipment	932,545	921,199	12
Construction in progress	11,488	22,253	---
Aggregate reserves	384,361	384,731	**
Other:			
Land	2,942	3,022	---
Other	27,430	28,811	18
Less accumulated depreciation, depletion and amortization	2,761,319	2,270,691	
Net property, plant and equipment	\$ 4,300,918	\$ 3,659,555	

* Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of \$2.00, \$1.59 and \$1.38 for the years ended December 31, 2008, 2007 and 2006, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which \$232.1 million and \$142.5 million were excluded from amortization at December 31, 2008 and 2007, 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 2008, 2007 and 2006. 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 impairments and goodwill, see Notes 3 and 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 based on spot market prices that exist at the end of the period 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 is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. 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 unless subsequent price changes eliminate or reduce an indicated write-down.

Due to low natural gas and oil prices that existed on December 31, 2008, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at December 31, 2008. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-down amounted to \$135.8 million (\$84.2 million after tax) for the year ended December 31, 2008. Prices subsequent to December 31, 2008, remained low and therefore the noncash write-down was not reduced or eliminated. Sustained downward movements in natural gas and oil prices subsequent to December 31, 2008, could result in future write-downs of the Company's natural gas and oil properties.

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 an additional write-down of its natural gas and oil properties of \$79.2 million (\$49.1 million after tax) 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.

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The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2008, in total and by the year in which such costs were incurred:

	Year Costs Incurred				
	Total	2008	2007	2006	2005 and prior
		<i>(In thousands)</i>			
Acquisition	\$129,723	\$89,367	\$9,114	\$15,067	\$16,175
Development	56,559	45,973	8,519	1,584	483
Exploration	41,825	33,994	7,111	720	---
Capitalized interest	3,974	2,950	431	303	290
Total costs not subject to amortization	\$232,081	\$172,284	\$25,175	\$17,674	\$16,948

Costs not subject to amortization as of December 31, 2008, consisted primarily of unevaluated leaseholds, drilling costs, seismic costs and capitalized interest associated primarily with oil and gas development in the Paradox Basin in Utah; Bakken area in western North Dakota; Big Horn Basin in Wyoming; south Texas properties; CBNG in the Powder River Basin of Wyoming and Montana; and the newly acquired properties in eastern Texas. 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 \$123.2 million at December 31, 2008. Accrued unbilled revenue at Montana-Dakota and Cascade was \$66.6 million at December 31, 2007. 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.

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 in excess of billings on uncompleted contracts of \$40.1 million and \$45.2 million at December 31, 2008 and 2007, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs on uncompleted contracts of \$106.9 million and \$81.4 million at December 31, 2008 and 2007, 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 \$86.9 million and \$80.3 million at December 31, 2008 and 2007, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to \$67.7 million and \$68.9 million at December 31, 2008 and 2007, respectively. The long-term retainage which was included in deferred charges and other assets - other was \$19.2 million and \$11.4 million at December 31, 2008 and 2007, respectively.

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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 24 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 estimated fair values of the Company's swap and collar agreements reflect the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date. These values are based upon, among other things, futures prices, volatility and time to maturity.

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 11.

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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 \$64,000 and \$11.6 million at December 31, 2008 and 2007, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were \$51.7 million and \$3.9 million at December 31, 2008 and 2007, 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 \$750,000 per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to \$500,000 per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made 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 resulting from the Company's adoption of SFAS No. 109 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 electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

The Company accounts for uncertain tax positions in accordance with FIN 48. FIN 48 establishes standards for measurement and recognition in financial statements of tax positions taken or expected to be taken in an income tax return. Under FIN 48, tax positions 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.

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Common stock split

On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 13.

Earnings per common share

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. In 2008, 2007 and 2006, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation

On January 1, 2006, the Company adopted SFAS No. 123 (revised). This accounting standard requires entities to recognize compensation expense in an amount equal to the grant-date fair value of share-based payments granted to employees. SFAS No. 123 (revised) was adopted using the modified prospective method, recognizing compensation expense for all awards granted after the date of adoption of the standard and for the unvested portion of previously granted awards that remain outstanding at the date of adoption.

For more information on the Company's stock-based compensation, see Note 14.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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,	2008	2007	2006
	<i>(In thousands)</i>		
Interest, net of amount capitalized	\$ 77,152	\$ 74,404	\$ 65,850
Income taxes	\$ 113,212	\$ 214,573	\$ 105,317

Income taxes paid for the year ended December 31, 2007, were higher than the amount paid for the years ended December 31, 2008 and 2006, 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

SFAS No. 157 In September 2006, the FASB issued SFAS No. 157. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The standard applies under other accounting pronouncements that

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require or permit fair value measurements with certain exceptions. SFAS No. 157 was effective for the Company on January 1, 2008. FSP FAS No. 157-2 delays the effective date of SFAS No. 157 for certain nonfinancial assets and nonfinancial liabilities to January 1, 2009. The types of assets and liabilities that are recognized at fair value for which the Company has not applied the provisions of SFAS No. 157, due to the delayed effective date, include nonfinancial assets and nonfinancial liabilities initially measured at fair value in a business combination or new basis event, certain fair value measurements associated with goodwill impairment testing, indefinite-lived intangible assets and nonfinancial long-lived assets measured at fair value for impairment assessment, and asset retirement obligations initially measured at fair value. The adoption of SFAS No. 157, 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.

SFAS No. 159 In February 2007, the FASB issued SFAS No. 159. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 was effective for the Company on January 1, 2008, and at adoption, the Company elected to measure its investments in certain fixed-income and equity securities at fair value in accordance with SFAS No. 159. These investments prior to January 1, 2008, were accounted for as available-for-sale investments and recorded at fair value with any unrealized gains or losses, net of income taxes, recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets until realized. Upon the adoption of SFAS No. 159, the unrealized gain on the available-for-sale investments of \$405,000 (after tax) was recorded as an increase to the January 1, 2008, balance of retained earnings. The adoption of SFAS No. 159 did not have a material effect on the Company's financial position or results of operations.

SFAS No. 141 (revised) In December 2007, the FASB issued SFAS No. 141 (revised). SFAS No. 141 (revised) 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. In addition, SFAS No. 141 (revised) requires that acquisition-related costs will be generally expensed as incurred. SFAS No. 141 (revised) also expands the disclosure requirements for business combinations. SFAS No. 141 (revised) was effective for the Company on January 1, 2009. The adoption of SFAS No. 141 (revised) did not have a material effect on the Company's financial position or results of operations.

SFAS No. 160 In December 2007, the FASB issued SFAS No. 160. SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 was effective for the Company on January 1, 2009. The adoption of SFAS No. 160 did not have a material effect on the Company's financial position or results of operations.

SFAS No. 161 In March 2008, the FASB issued SFAS No. 161. SFAS No. 161 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 Statement was effective for the Company on January 1, 2009. The adoption of SFAS No. 161 will require additional disclosures regarding the Company's derivative instruments; however, it will not impact the Company's financial position or results of operations.

FSP FAS No. 132(R)-1 In December 2008, the FASB issued FSP FAS No. 132(R)-1. FSP FAS No. 132(R)-1 provides 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

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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 statement was effective for the Company on January 1, 2009. The adoption of FSP FAS No. 132(R)-1 will require additional disclosures regarding the Company's defined benefit pension and other postretirement plans; however, it will 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 are effective for the Company on December 31, 2009.

Comprehensive income

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

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2008, 2007 and 2006, were as follows:

	2008	2007	2006
	(In thousands)		
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain on derivative instruments arising during the period, net of tax of \$30,414, \$3,989 and \$12,359 in 2008, 2007 and 2006, respectively	\$49,623	\$6,508	\$19,743
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of \$3,795, \$12,504 and \$(16,194) in 2008, 2007 and 2006, respectively	6,175	20,013	(25,867)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	43,448	(13,505)	45,610
Pension liability adjustment, net of tax of \$(8,750), \$1,835 and \$1,122 in 2008, 2007 and 2006, respectively	(13,751)	3,012	1,761
Foreign currency translation adjustment, net of tax of \$(6,108) and \$3,606 in 2008 and 2007, respectively	(9,534)	7,177	(1,585)
Net unrealized gain on available-for-sale investments, net of tax of \$270 in 2007	---	405	---
Total other comprehensive income (loss)	\$20,163	\$(2,911)	\$45,786

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The after-tax components of accumulated other comprehensive income (loss) as of December 31, 2008, 2007 and 2006, were as follows:

	Net Unrealized Gain on Derivative Instruments Qualifying as Hedges	Pension Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain on Available- for-sale Investment	Total Accumulated Other Comprehensive Income (Loss)
<i>(In thousands)</i>					
Balance at December 31, 2006	\$19,443	\$(24,342)	\$(1,583)	\$---	\$(6,482)
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

NOTE 2 - ACQUISITIONS

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.

In 2006, the Company acquired a construction services business in Nevada, natural gas and oil production properties in Wyoming, and construction materials and contracting businesses in California and Washington, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2006, consisting of the Company's common stock and cash, was \$120.6 million.

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 certain of the above acquisitions made in 2008, final fair market values are 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

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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 on January 23, 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.

On July 10, 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).

In accordance with SFAS No. 144, the Company's consolidated financial statements and accompanying notes for prior periods present the results of operations of Innovatum and the domestic independent power production assets as discontinued operations. In addition, the assets and liabilities of these operations were treated as held for sale, and as a result, no depreciation, depletion and amortization expense was recorded from the time each of the assets was classified as held for sale.

In accordance with SFAS No. 142, at the time the Company committed to the plan to sell each of the assets, the Company was required to test the respective assets for goodwill impairment. The fair value of Innovatum, a reporting unit for goodwill impairment testing, was estimated using the expected proceeds from the sale, which was estimated to be the current book value of the assets of Innovatum other than its goodwill. As a result, a goodwill impairment of \$4.3 million (before tax) was recognized and recorded as part of discontinued operations, net of tax, in the Consolidated Statements of Income in the third quarter of 2006. There were no goodwill impairments associated with the other assets held for sale.

Operating results related to Innovatum for the years ended December 31, 2007 and 2006, were as follows:

	2007	2006
	(In thousands)	
Operating revenues	\$ 1,748	\$ 1,827
Loss from discontinued operations before income tax benefit	(210)	(5,994)
Income tax benefit	(316)	(3,834)
Income (loss) from discontinued operations, net of tax	\$ 106	\$ (2,160)

The income tax benefit for the year ended December 31, 2006, is larger than the customary relationship between the income tax benefit and the loss before tax due to a capital loss tax benefit (which reflects the effect of the \$4.3 million and \$4.0 million goodwill impairments in 2006 and 2004, respectively) resulting from the sale of the Innovatum stock.

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Operating results related to the domestic independent power production assets for the years ended December 31, 2007 and 2006, were as follows:

	2007	2006
	<i>(In thousands)</i>	
Operating revenues	\$ 125,867	\$ 66,145
Income from discontinued operations (including gain on disposal in 2007 of \$142.4 million) before income tax expense (benefit)	177,666	9,276
Income tax expense (benefit)	68,438	(863)
Income from discontinued operations, net of tax	\$ 109,228	\$ 10,139

The income tax benefit for the year ended December 31, 2006, reflects a renewable electricity production tax credit of \$4.4 million.

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 under EITF No. 91-6 ratably over the terms of the related contract. Arrangements with multiple revenue-generating activities were recognized under EITF No. 00-21 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.

The carrying amounts of the assets and liabilities related to discontinued operations at December 31, 2007, were not material.

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, 2008 and 2007, 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 22 and 24 years remaining under the contracts. Alusa, Brascan 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 September 2004, Centennial Resources, through indirect wholly owned subsidiaries, acquired a 50-percent ownership interest in Hartwell, which owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. In July 2007, the Company sold its ownership interest in Hartwell, and realized a gain of \$10.1 million (\$6.1 million after tax) from the sale which is recorded in earnings from equity method investments on the Consolidated Statements of Income.

At December 31, 2008 and 2007, the Company's equity method investments had total assets of \$294.7 million and \$398.4 million, respectively, and long-term debt of \$158.0 million and \$211.2 million, respectively. The Company's investment in its equity method investments was approximately \$44.4 million and \$59.0 million, including undistributed earnings of \$6.8 million and \$6.9 million, at December 31, 2008 and 2007, respectively.

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NOTE 5 - GOODWILL AND OTHER INTANGIBLE ASSETS

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
<i>(In thousands)</i>			
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.

The changes in the carrying amount of goodwill for the year ended December 31, 2007, were as follows:

	Balance as of January 1, 2007	Goodwill Acquired During the Year*	Balance as of December 31, 2007
<i>(In thousands)</i>			
Electric	\$ ---	\$ ---	\$ ---
Natural gas distribution	---	171,129	171,129
Construction services	86,942	4,443	91,385
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and contracting	136,197	25,828	162,025
Other	---	---	---
Total	\$ 224,298	\$ 201,400	\$ 425,698

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

Other amortizable intangible assets at December 31, 2008 and 2007, were as follows:

	2008	2007
<i>(In thousands)</i>		
Customer relationships	\$ 21,842	\$ 21,834
Accumulated amortization	(6,985)	(4,444)
	14,857	17,390
Noncompete agreements	10,080	10,655
Accumulated amortization	(5,126)	(3,654)
	4,954	7,001
Other	10,949	5,943
Accumulated amortization	(2,368)	(2,542)
	8,581	3,401
Total	\$ 28,392	\$ 27,792

Amortization expense for intangible assets for the years ended December 31, 2008, 2007 and 2006, was \$5.1 million, \$4.4 million and \$4.3 million, respectively. Estimated

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amortization expense for intangible assets is \$5.1 million in 2009, \$3.7 million in 2010, \$3.1 million in 2011, \$3.0 million in 2012, \$2.5 million in 2013 and \$11.0 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:

	2008	2007
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefits	\$ 119,868	\$ 21,613
Natural gas supply derivatives	89,813	16,324
Natural gas cost recoverable through rate adjustments	51,699	3,896
Deferred income taxes*	46,855	43,866
Long-term debt refinancing costs	9,991	10,605
Plant costs	8,534	4,930
Other	12,802	11,916
Total regulatory assets	339,562	113,150
Regulatory liabilities:		
Plant removal and decommissioning costs	94,737	89,991
Deferred income taxes*	65,909	17,630
Taxes refundable to customers	25,642	22,580
Natural gas supply derivatives	5,540	5,631
Natural gas costs refundable through rate adjustments	64	11,568
Other	7,460	8,250
Total regulatory liabilities	199,352	155,650
Net regulatory position	\$ 140,210	\$ (42,500)

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

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.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 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 SFAS No. 71 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. 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

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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, 2008, the Company had no outstanding foreign currency or interest rate hedges.

Cascade and Intermountain

At December 31, 2008, Cascade and Intermountain held natural gas swap agreements which were not designated as hedges. Cascade and Intermountain utilize natural gas swap agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas on their forecasted purchases of natural gas for 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 apply SFAS No. 71 and 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. 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. At December 31, 2008, the fair value of Cascade's natural gas swap agreements is presented net of the collateral provided to the counterparty of \$11.1 million.

Fidelity

At December 31, 2008, Fidelity held natural gas swaps, a basis swap and collar agreements 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 on its forecasted sales of natural gas production. These derivatives were designated as cash flow hedges of the forecasted sales of the related production.

The fair value of the hedging instruments 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. 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 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 production are generally based on market prices.

For the years ended December 31, 2008, 2007 and 2006, 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 the line item in which the hedged item is recorded. As of December 31, 2008, the maximum term of the swap

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and collar agreements, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 36 months. The Company estimates that over the next 12 months, net gains of approximately \$47.6 million (after tax) will be reclassified from accumulated other comprehensive income into earnings, subject to changes in natural gas market prices, as the hedged transactions affect earnings.

NOTE 8 - FAIR VALUE MEASUREMENTS

On January 1, 2008, the Company adopted SFAS No. 157 and SFAS No. 159, as discussed in Note 1.

Upon the adoption of SFAS No. 159, the Company elected to measure its investments in certain fixed-income and equity securities at fair value. These investments had previously been accounted for as available-for-sale investments in accordance with SFAS No. 115. 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 \$27.7 million as of December 31, 2008, are classified as Investments on the Consolidated Balance Sheets. The decrease in the fair value of these investments for the year ended December 31, 2008, was \$8.6 million (before tax), which is considered part of the cost of the plan, and 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, 2008, are accounted for as available-for-sale in accordance with SFAS No. 115 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.

SFAS No. 157 defines fair value 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:

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Fair Value Measurements at December 31, 2008, Using				
	Balance at December 31, 2008	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(In thousands)				
Assets:				
Available-for-sale securities	\$ 39,125	\$ 27,725	\$ 11,400	\$ ---
Commodity derivative instruments - current	78,164	---	78,164	---
Commodity derivative instruments - noncurrent	3,222	---	3,222	---
Total assets measured at fair value	\$ 120,511	\$ 27,725	\$ 92,786	\$ ---
Liabilities:				
Commodity derivative instruments - current	\$ 56,529	\$ ---	\$ 56,529	\$ ---
Commodity derivative instruments - noncurrent	23,534	---	23,534	---
Total liabilities measured at fair value	\$ 80,063	\$ ---	\$ 80,063	\$ ---

Note: The fair value of the commodity derivative agreements in a current liability position is presented net of collateral provided to the counterparty by Cascade of \$11.1 million.

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 available-for-sale securities is based on comparable market transactions. The estimated fair values of the Company's commodity derivative instruments reflects the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date. These values are based upon, among other things, futures prices, volatility and time to maturity.

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:

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
(In thousands)				
Long-term debt	\$ 1,647,302	\$ 1,577,907	\$ 1,308,463	\$ 1,293,863

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The estimated fair value of the Company's commodity derivative instruments at December 31 was as follows:

	2007	
	Carrying Amount	Fair Value
	(In thousands)	
Commodity derivative instruments – current asset	\$ 12,740	\$ 12,740
Commodity derivative instruments – current liability	\$ (14,799)	\$ (14,799)
Commodity derivative instruments – noncurrent asset	\$ 3,419	\$ 3,419
Commodity derivative instruments – noncurrent liability	\$ (2,570)	\$ (2,570)

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

NOTE 9 – SHORT-TERM BORROWINGS

MDU Resources Group, Inc. In connection with the funding of the Intermountain acquisition, on September 26, 2008, the Company entered into a term loan agreement providing for a commitment amount of \$175 million. On October 1, 2008, the Company borrowed \$170 million under this agreement, which expired on March 24, 2009. There was \$57.0 million outstanding under the term loan agreement at December 31, 2008, which was repaid on March 2, 2009 with funds from an existing term loan borrowing agreement.

The agreement contains customary covenants and default 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 (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 only, excluding subsidiaries) to be greater than 65 percent. The agreement also includes 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 only, excluding subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. The Company was in compliance with these covenants and met the required conditions at December 31, 2008.

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

Cascade Natural Gas Corporation Cascade has a revolving credit agreement with various banks totaling \$50 million with certain provisions allowing for increased borrowings, up to a maximum of \$75 million. The \$50 million credit agreement expires on December 28, 2012, with provisions allowing for an extension of up to two years upon consent of the banks. Under the terms of the \$50 million credit agreement, \$48.1 million and \$1.7 million were outstanding at December 31, 2008 and 2007, respectively. Cascade also had a revolving credit agreement totaling \$15 million, which expired on March 11, 2009. There was no amount outstanding under the \$15 million credit agreement at December 31, 2008. These borrowings are classified as short-term borrowings as Cascade intends to repay the borrowings within one year. The weighted average interest rate for borrowings outstanding at December 31, 2008, was less than one percent. As of December 31, 2008, there were outstanding letters of credit, as discussed in Note 20, of which \$1.9 million reduced amounts available under the \$50 million credit agreement.

In order to borrow under Cascade's credit agreements, Cascade must be in compliance with the applicable covenants and certain other conditions. This includes a covenant not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade was in compliance with these covenants and met the required conditions at December 31, 2008.

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Cascade's credit agreements contain 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, the agreement will be in default. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

NOTE 10 - LONG-TERM DEBT AND INDENTURE PROVISIONS

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

	2008	2007
	<i>(In thousands)</i>	
First mortgage bonds and notes:		
Secured Medium-Term Notes, Series A, at a weighted average rate of 8.26%, due on dates ranging from October 1, 2009 to April 1, 2012	\$ 5,500	\$ 20,500
Senior Notes, 5.98%, due December 15, 2033	30,000	30,000
Total first mortgage bonds and notes	35,500	50,500
Senior Notes at a weighted average rate of 5.96%, due on dates ranging from February 2, 2009 to March 8, 2037	1,271,227	1,064,000
Commercial paper at a weighted average rate of 4.15%, supported by revolving credit agreements	172,500	61,000
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
Credit agreements at a weighted average rate of 3.69%, due on dates ranging from May 1, 2009 to November 30, 2038	44,205	8,286
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	42,971	43,679
Discount	(101)	(2)
Total long-term debt	1,647,302	1,308,463
Less current maturities	78,666	161,682
Net long-term debt	\$1,568,636	\$1,146,781

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2008, aggregate \$78.7 million in 2009; \$49.1 million in 2010; \$94.8 million in 2011; \$290.7 million in 2012; \$258.8 million in 2013 and \$875.2 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2008.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling \$125 million (with provision for an increase, 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 at December 31, 2008 and 2007. The credit agreement supports the Company's \$125 million commercial paper program. Although volatility in the capital markets has recently increased significantly, the Company continues to issue commercial paper to meet its current needs. Under the Company's commercial paper program, \$22.5 million and \$61.0 million was outstanding at December 31, 2008 and 2007, respectively. 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 (supported by the credit agreement, which expires on June 21, 2011).

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In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions, including covenants 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. The Company was in compliance with these covenants and met the required conditions at December 31, 2008. In the event the Company does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Mortgage. Generally, those restrictions require the Company to fund \$1.43 of unfunded property or use \$1.00 of refunded bonds for each dollar of indebtedness incurred under the Mortgage and, in some cases, to certify to the trustee that annual earnings (pretax and before interest charges), as defined in the Mortgage, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the tests, as of December 31, 2008, the Company could have issued approximately \$620 million of additional first mortgage bonds.

Approximately \$618.8 million in net book value of the Company's electric and natural gas distribution properties at December 31, 2008, with certain exceptions, are subject to the lien of the Mortgage and to the junior lien of the Indenture.

MDU Energy Capital, LLC On October 1, 2008, MDU Energy Capital entered into an amendment to its master shelf agreement which increased the facility amount from \$125 million to \$175 million. Under the terms of the master shelf agreement, \$165.0 million and \$85.0 million was outstanding at December 31, 2008 and 2007, respectively. MDU Energy Capital may incur additional indebtedness under the master shelf agreement until the earlier of August 14, 2010, or such time as the agreement is terminated by either of the parties thereto.

On October 1, 2008, MDU Energy Capital borrowed \$80.0 million under the agreement. The indebtedness consists of \$30 million of senior notes due October 1, 2013, and \$50 million of senior notes due October 1, 2015. MDU Energy Capital used the proceeds from the borrowing to pay a dividend to the Company which, in turn, used this dividend to partially fund the acquisition of Intermountain, as previously discussed.

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. MDU Energy Capital was in compliance with these covenants and met the required conditions at December 31, 2008. 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).

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Intermountain Gas Company Intermountain has a revolving credit agreement with various banks totaling \$65 million with certain provisions allowing for increased borrowings, up to a maximum of \$70 million. The credit agreement expires on August 31, 2010. Under the terms of the credit agreement, \$36.5 million was outstanding at December 31, 2008.

In order to borrow under Intermountain's credit agreement, Intermountain must be in compliance with the applicable covenants and certain other conditions, including covenants 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 was in compliance with these covenants and met the required conditions at December 31, 2008. In the event Intermountain does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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.

Centennial Energy Holdings, Inc. Centennial has a revolving credit agreement with various banks and institutions totaling \$400 million with certain provisions allowing for increased borrowings. The credit agreement supports Centennial's \$400 million commercial paper program. Although volatility in the capital markets has recently increased significantly, the Company continues to issue commercial paper to meet its current needs. There were no outstanding borrowings under the Centennial credit agreement at December 31, 2008 and 2007. Under the Centennial commercial paper program, \$150.0 million was outstanding at December 31, 2008, and there was no amount outstanding at December 31, 2007. 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 (supported by the Centennial credit agreement). The revolving credit agreement includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of \$450 million and expires on December 13, 2012. As of December 31, 2008, Centennial had letters of credit outstanding, as discussed in Note 20, of which \$24.3 million reduced amounts available under the agreement.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to \$550 million. Under the terms of the master shelf agreement, \$509.0 million and \$418.5 million was outstanding at December 31, 2008 and 2007, respectively. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009.

In order to borrow under Centennial's credit agreement and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions, including covenants 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. Centennial and such subsidiaries were in

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compliance with these covenants and met the required conditions at December 31, 2008. In the event Centennial or such subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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 In December 2008, Williston Basin entered into an uncommitted long-term private shelf agreement that allows for borrowings up to \$125 million. Under the terms of the private shelf agreement, \$72.5 million was outstanding at December 31, 2008. The \$72.5 million outstanding consists of \$20.0 million of notes issued under the private shelf agreement and \$52.5 million of notes issued under a master shelf agreement that expired on December 20, 2008. At December 31, 2007, \$80.0 million was outstanding under the prior agreement. The ability to request additional borrowings under this private shelf agreement expires on December 23, 2010, with certain provisions allowing for an extension to December 23, 2011.

In order to borrow under its uncommitted long-term private shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions, including covenants 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. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2008. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

NOTE 11 - 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 and reclamation of certain aggregate properties.

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

	2008	2007
	(In thousands)	
Balance at beginning of year	\$64,453	\$56,179
Liabilities incurred	2,943	4,149
Liabilities acquired	2,369	652
Liabilities settled	(3,188)	(5,896)
Accretion expense	3,191	3,081
Revisions in estimates	207	6,100
Other	172	188
Balance at end of year	\$70,147	\$64,453

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, 2008 and 2007, was \$5.9 million and \$5.8 million, respectively.

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NOTE 12 - PREFERRED STOCKS

Preferred stocks at December 31 were as follows:

	2008	2007
<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.

NOTE 13 - COMMON STOCK

On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split to be effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on July 26, 2006, to common stockholders of record on July 12, 2006. Certain common stock information appearing in the accompanying consolidated financial statements has been restated in accordance with accounting principles generally accepted in the United States of America to give retroactive effect to the stock split.

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In 1998, the Company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right for each outstanding share of the Company's common stock. The rights expired on December 31, 2008.

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 July 2006 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 January 2006 through June 2006, April 2007 through September 30, 2008, and October 22, 2008 through December 2008, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2008, there were 20.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

NOTE 14 - STOCK-BASED COMPENSATION

The Company has several stock-based compensation plans and is authorized to grant options, restricted stock and stock for up to 17.1 million shares of common stock and has granted options, restricted stock and stock of 7.3 million shares through December 31, 2008. 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 \$3.7 million, net of income taxes of \$2.3 million in 2008; \$4.7 million, net of income taxes of \$3.1 million in 2007; and \$3.5 million, net of income taxes of \$2.2 million in 2006.

As of December 31, 2008, total remaining unrecognized compensation expense related to stock-based compensation was approximately \$5.0 million (before income taxes) which will be amortized over a weighted average period of 1.7 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, 2008, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	1,495,908	\$13.09
Forfeited	(15,770)	12.30
Exercised	(476,314)	12.48
Balance at end of year	1,003,824	13.39
Exercisable at end of year	976,856	\$13.38

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Summarized information about stock options outstanding and exercisable as of December 31, 2008, 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)
\$ 8.88 – 11.00	15,186	1.1	\$ 9.86	\$ 178	15,186	\$ 9.86	\$ 178
11.01 – 14.00	915,659	2.2	13.20	7,673	894,124	13.21	7,487
14.01 – 17.13	<u>72,979</u>	2.2	16.46	<u>374</u>	<u>67,546</u>	16.48	<u>345</u>
Balance at end of year	1,003,824	2.2	\$13.39	\$8,225	976,856	\$13.38	\$ 8,010

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, 2008, 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 2.2 years at December 31, 2008.

The Company received cash of \$5.9 million, \$10.2 million and \$4.5 million from the exercise of stock options for the years ended December 31, 2008, 2007 and 2006, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2008, 2007 and 2006, was \$8.1 million, \$11.2 million and \$4.4 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, 2008, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	26,733	\$13.22
Vested	---	---
Forfeited	<u>(6,127)</u>	13.22
Nonvested at end of period	20,606	\$13.22

The fair value of restricted stock awards that vested during the year ended December 31, 2006, was \$1.8 million.

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 45,675 shares with a fair value of \$1.2 million, 48,228 shares with a fair value of \$1.5 million and 50,627 shares with a fair value of \$1.3 million issued under this plan during the years ended December 31, 2008, 2007 and 2006, 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, 2008, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2006	2006-2008	185,182
February 2007	2007-2009	175,596
February 2008	2008-2010	186,089

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, 2008, 2007 and 2006, was \$30.71, \$23.55 and \$25.22, per share, respectively. The grant-date fair value for the performance shares was determined by Monte Carlo simulation using a blended volatility term structure comprised of 50 percent historical volatility and 50 percent implied volatility and a risk-free interest rate term structure 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 \$1.64, \$1.25 and \$1.37 per target share for the 2008, 2007 and 2006 awards, respectively. The fair value of performance share awards that vested during the years ended December 31, 2008, 2007 and 2006, was \$8.5 million, \$6.0 million and \$2.2 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2008, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	624,499	\$21.91
Granted	192,147	30.71
Additional performance shares earned	61,461	18.36
Vested	(317,542)	18.36
Forfeited	(13,698)	26.57
Nonvested at end of period	546,867	\$26.55

NOTE 15 - INCOME TAXES

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

	2008	2007	2006
	<i>(In thousands)</i>		
United States	\$436,029	\$508,210	\$469,741
Foreign	5,120	4,600	4,148
Income before income taxes	\$441,149	\$512,810	\$473,889

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

	2008	2007	2006
	<i>(In thousands)</i>		
Current:			
Federal	\$ 82,279	\$ 106,399	\$ 108,843
State	(184)	15,135	18,487
Foreign	(104)	235	136
	81,991	121,769	127,466
Deferred:			
Income taxes –			
Federal	59,963	58,030	34,693
State	5,332	9,656	4,357
Investment tax credit	(405)	(414)	(405)
	64,890	67,272	38,645
Change in uncertain tax benefits	422	869	---
Change in accrued interest	173	114	---
Total income tax expense	\$ 147,476	\$ 190,024	\$ 166,111

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

	2008	2007
	<i>(In thousands)</i>	
Deferred tax assets:		
Accrued pension costs	\$ 93,371	\$ 44,002
Regulatory matters	46,855	43,866
Asset retirement obligations	22,707	15,163
Deferred compensation	12,015	13,677
Other	62,456	45,335
Total deferred tax assets	237,404	162,043
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	562,326	498,933
Basis differences on natural gas and oil producing properties	284,231	260,417
Regulatory matters	65,909	17,630
Natural gas and oil price swap and collar agreements	30,414	3,989
Other	42,725	42,044
Total deferred tax liabilities	985,605	823,013
Net deferred income tax liability	\$(748,201)	\$(660,970)

As of December 31, 2008 and 2007, 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, 2007, to December 31, 2008, to deferred income tax expense:

	2008
	(In thousands)
Change in net deferred income tax liability from the preceding table	\$ 87,231
Deferred taxes associated with other comprehensive income	(11,761)
Deferred taxes associated with acquisitions	(20,700)
Other	10,120
Deferred income tax expense for the period	\$ 64,890

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

Years ended December 31,	2008		2007		2006	
	Amount	%	Amount	%	Amount	%
(Dollars in thousands)						
Computed tax at federal statutory rate	\$ 154,402	35.0	\$ 179,484	35.0	\$ 165,861	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	10,709	2.4	17,121	3.3	17,786	3.8
Domestic production activities deduction	(3,031)	(.7)	(4,787)	(.9)	(2,324)	(.5)
Depletion allowance	(2,932)	(.7)	(4,073)	(.8)	(4,784)	(1.0)
Deductible K-Plan dividends	(2,144)	(.5)	(2,134)	(.4)	---	---
Federal renewable energy credit	(1,235)	(.3)	---	---	---	---
Resolution of tax matters and uncertain tax positions	595	.1	208	---	(3,660)	(.8)
Foreign operations	423	.1	9,603	1.8	136	---
Other	(9,311)	(2.0)	(5,398)	(.9)	(6,904)	(1.4)
Total income tax expense	\$ 147,476	33.4	\$ 190,024	37.1	\$ 166,111	35.1

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 accordance with SFAS No. 109, 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 \$34 million at December 31, 2008. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2008, was approximately \$10.8 million, which was largely

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recognized in 2007. Future earnings will also be subject to additional U.S. taxes, net of allowable foreign tax credits.

On January 1, 2007, the Company adopted FIN 48. 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.

Upon the adoption of FIN 48, 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:

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

Included in the balance of unrecognized tax benefits at December 31, 2008, 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, 2008, was \$5.7 million, including approximately \$614,000 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, 2008, 2007 and 2006, the Company recognized approximately \$819,000, \$680,000 and \$7,100, respectively, in interest expense. Penalties were not material in 2008, 2007 and 2006. The Company recognized interest income of approximately \$223,000, \$480,000 and \$1.5 million for the years ended December 31, 2008, 2007 and 2006, respectively. The Company had accrued liabilities of approximately \$1.4 million, \$718,000 and \$436,000 at December 31, 2008, 2007 and 2006, respectively, for the payment of interest.

NOTE 16 - BUSINESS SEGMENT DATA

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

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural

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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 protection 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 energy-related management 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:

	2008	2007	2006
	<i>(In thousands)</i>		
External operating revenues:			
Electric	\$ 208,326	\$ 193,367	\$ 187,301
Natural gas distribution	1,036,109	532,997	351,988
Pipeline and energy services	440,764	369,345	349,997
	1,685,199	1,095,709	889,286
Construction services	1,256,759	1,102,566	987,079
Natural gas and oil production	420,637	288,148	251,153
Construction materials and contracting	1,640,683	1,761,473	1,877,021
Other	---	---	---
	3,318,079	3,152,187	3,115,253
Total external operating revenues	\$ 5,003,278	\$ 4,247,896	\$ 4,004,539
Intersegment operating revenues:			
Electric	\$ ---	\$ ---	\$ ---
Natural gas distribution	---	---	---
Construction services	560	649	503
Pipeline and energy services	91,389	77,718	93,723
Natural gas and oil production	291,642	226,706	232,799
Construction materials and contracting	---	---	---
Other	10,501	10,061	8,117
Intersegment eliminations	(394,092)	(315,134)	(335,142)
Total intersegment operating revenues	\$ ---	\$ ---	\$ ---
Depreciation, depletion and amortization:			
Electric	\$ 24,030	\$ 22,549	\$ 21,396
Natural gas distribution	32,566	19,054	9,776
Construction services	13,398	14,314	15,449
Pipeline and energy services	23,654	21,631	13,288
Natural gas and oil production	170,236	127,408	106,768
Construction materials and contracting	100,853	95,732	88,723
Other	1,283	1,244	1,131
Total depreciation, depletion and amortization	\$ 366,020	\$ 301,932	\$ 256,531
Interest expense:			
Electric	\$ 8,674	\$ 6,737	\$ 6,493
Natural gas distribution	24,004	13,566	3,885
Construction services	4,893	4,878	6,295
Pipeline and energy services	8,314	8,769	8,094
Natural gas and oil production	12,428	8,394	9,864
Construction materials and contracting	24,291	23,997	25,943
Other	374	10,717	11,775
Intersegment eliminations	(1,451)	(4,821)	(254)
Total interest expense	\$ 81,527	\$ 72,237	\$ 72,095

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	2008	2007	2006
	(In thousands)		
Income taxes:			
Electric	\$ 8,225	\$ 8,528	\$ 7,403
Natural gas distribution	18,827	6,477	2,108
Construction services	26,952	26,829	16,497
Pipeline and energy services	15,427	18,524	18,938
Natural gas and oil production	68,701	78,348	78,960
Construction materials and contracting	8,947	39,045	46,245
Other	397	12,273	(4,040)
Total income taxes	\$ 147,476	\$ 190,024	\$ 166,111
Earnings on common stock:			
Electric	\$ 18,755	\$ 17,700	\$ 14,401
Natural gas distribution	34,774	14,044	5,680
Construction services	49,782	43,843	27,851
Pipeline and energy services	26,367	31,408	32,126
Natural gas and oil production	122,326	142,485	145,657
Construction materials and contracting	30,172	77,001	85,702
Other	10,812	(4,380)	(4,324)
Earnings on common stock before income from discontinued operations	292,988	322,101	307,093
Income from discontinued operations, net of tax	---	109,334	7,979
Total earnings on common stock	\$ 292,988	\$ 431,435	\$ 315,072
Capital expenditures:			
Electric	\$ 72,989	\$ 91,548	\$ 39,055
Natural gas distribution	398,116	500,178	15,398
Construction services	24,506	18,241	31,354
Pipeline and energy services	42,960	39,162	42,749
Natural gas and oil production	710,742	283,589	328,979
Construction materials and contracting	127,578	189,727	141,088
Other	774	1,621	2,052
Net proceeds from sale or disposition of property	(86,927)	(24,983)	(30,501)
Net capital expenditures before discontinued operations	1,290,738	1,099,083	570,174
Discontinued operations	---	(548,216)	33,090
Total net capital expenditures	\$ 1,290,738	\$ 550,867	\$ 603,264
Assets:			
Electric*	\$ 479,639	\$ 428,200	\$ 353,593
Natural gas distribution*	1,548,005	942,454	264,102
Construction services	476,092	456,564	401,832
Pipeline and energy services	506,872	500,755	474,424
Natural gas and oil production	1,792,792	1,299,406	1,173,797
Construction materials and contracting	1,552,296	1,642,729	1,562,868
Other**	232,149	322,326	672,858
Total assets	\$ 6,587,845	\$ 5,592,434	\$ 4,903,474

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	2008	2007	2006
	(In thousands)		
Property, plant and equipment:			
Electric*	\$ 848,725	\$ 784,705	\$ 703,838
Natural gas distribution*	1,429,487	948,446	289,106
Construction services	111,301	101,935	94,754
Pipeline and energy services	640,921	600,712	562,596
Natural gas and oil production	2,477,402	1,923,899	1,636,245
Construction materials and contracting	1,524,029	1,538,716	1,410,657
Other	30,372	31,833	30,529
Less accumulated depreciation, depletion and amortization	2,761,319	2,270,691	1,735,302
Net property, plant and equipment	\$ 4,300,918	\$ 3,659,555	\$ 2,992,423

* Includes allocations of common utility property.

** Includes the domestic independent power production assets in 2006 that were sold in 2007, and 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: 2008 results reflect an \$84.2 million after-tax noncash write-down of natural gas and oil properties.

The pipeline and energy services segment recognized income from discontinued operations, net of tax, of \$106,000 for the year ended December 31, 2007, and a loss from discontinued operations, net of tax, of \$2.1 million for the year ended December 31, 2006. The Other category reflects income from discontinued operations, net of tax, of \$109.2 million and \$10.1 million for the years ended December 31, 2007 and 2006, respectively.

Excluding income (loss) 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 2008, 2007 and 2006 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 noncash transactions were \$97.6 million in 2008, \$217.3 million in 2007 and immaterial in 2006.

NOTE 17 - EMPLOYEE BENEFIT PLANS

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

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

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
	<i>(In thousands)</i>			
Change in benefit obligation:				
Benefit obligation at beginning of year	\$359,923	\$298,398	\$81,581	\$67,724
Service cost	8,812	9,098	1,977	1,865
Interest cost	21,264	18,591	5,079	4,212
Plan participants' contributions	---	---	2,120	1,790
Amendments	---	---	(382)	---
Actuarial (gain) loss	(8,336)	(8,079)	763	482
Acquisition	---	63,556	9,872	11,734
Benefits paid	(23,138)	(21,641)	(6,685)	(6,226)
Benefit obligation at end of year	358,525	359,923	94,325	81,581
Change in plan assets:				
Fair value of plan assets at beginning of year	330,966	259,275	73,684	58,747
Actual gain (loss) on plan assets	(83,960)	28,393	(20,058)	2,357
Employer contribution	2,346	4,236	3,212	3,888
Plan participants' contributions	---	---	2,120	1,790
Acquisition	---	60,703	7,812	13,128
Benefits paid	(23,138)	(21,641)	(6,685)	(6,226)
Fair value of plan assets at end of year	226,214	330,966	60,085	73,684
Funded status – under	\$(132,311)	\$(28,957)	\$(34,240)	\$(7,897)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost (noncurrent)	\$ ---	\$ 10,253	\$ ---	\$ 664
Accrued benefit liability (current)	---	---	(407)	(408)
Accrued benefit liability (noncurrent)	(132,311)	(39,210)	(33,833)	(8,153)
Net amount recognized	\$(132,311)	\$(28,957)	\$(34,240)	\$(7,897)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial (gain) loss	\$131,081	\$30,006	\$23,418	\$(2,466)
Prior service cost (credit)	2,685	3,350	(8,151)	(10,524)
Transition obligation	---	---	8,503	10,628
Total	\$133,766	\$33,356	\$23,770	\$(2,362)

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

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

The accumulated benefit obligation for the defined benefit pension plans reflected above was \$312.1 million and \$307.7 million at December 31, 2008 and 2007, respectively.

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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, 2008 and 2007, were as follows:

	2008	2007
	<i>(In thousands)</i>	
Projected benefit obligation	\$358,525	\$106,236
Accumulated benefit obligation	\$312,110	\$95,435
Fair value of plan assets	\$226,214	\$94,845

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31, 2008, 2007 and 2006, were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
	(In thousands)					
Components of net periodic benefit cost:						
Service cost	\$8,812	\$9,098	\$8,901	\$1,977	\$1,865	\$2,015
Interest cost	21,264	18,591	16,056	5,079	4,212	3,633
Expected return on assets	(26,501)	(22,524)	(19,913)	(5,657)	(4,776)	(4,119)
Amortization of prior service cost (credit)	665	756	913	(2,755)	(1,300)	46
Recognized net actuarial (gain) loss	1,050	1,605	1,699	594	73	(243)
Amortization of net transition obligation (asset)	---	---	(3)	2,125	2,125	2,125
Net periodic benefit cost, including amount capitalized	5,290	7,526	7,653	1,363	2,199	3,457
Less amount capitalized	642	991	689	307	373	261
Net periodic benefit cost	4,648	6,535	6,964	1,056	1,826	3,196
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	102,125	(11,095)	(22,983)	26,478	1,507	(6,340)
Acquisition-related actuarial loss	---	12,291	---	---	9,818	---
Prior service credit	---	---	---	(382)	---	---
Acquisition-related prior service credit	---	(1,842)	---	---	(12,472)	---
Amortization of actuarial gain (loss)	(1,050)	(1,605)	(1,699)	(594)	(73)	243
Amortization of prior service (cost) credit	(665)	(756)	(913)	2,755	1,300	(46)
Amortization of net transition (obligation) asset	---	---	3	(2,125)	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	100,410	(3,007)	(25,592)	26,132	(2,045)	(8,268)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	\$105,058	\$3,528	\$(18,628)	\$27,188	\$(219)	(5,072)

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2009 are \$3.9 million and \$605,000, 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 2009 are \$1.1 million, \$2.8 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	
	2008	2007	2008	2007
Discount rate	6.25%	6.00%	6.25%	6.00%
Rate of compensation increase	4.00%	4.20%	4.00%	4.50%

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

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Discount rate	6.00%	5.75%	6.00%	5.75%
Expected return on plan assets	8.50%	8.40%	7.50%	7.50%
Rate of compensation increase	4.20%	4.20%	4.50%	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:

	2008	2007
Health care trend rate assumed for next year	6.0%-9.0%	6.0%-10.0%
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, 2008:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	\$ 157	\$ (1,092)
Effect on postretirement benefit obligation	\$ 2,809	\$ (10,944)

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The Company's defined benefit pension plans' asset allocation at December 31, 2008 and 2007, and weighted average targeted asset allocations at December 31, 2008, were as follows:

Asset Category	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
	2008	2007	2008
Equity securities	46%	66%	70%
Fixed-income securities	25	29	30*
Other**	29	5	---
Total	100%	100%	100%

* Includes target for both fixed-income securities and other.

** Largely cash and cash equivalents.

The Company's pension assets are managed by 11 outside investment managers. The Company's other postretirement assets are managed by three outside investment managers. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and future contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy. Pension assets are largely valued based on quoted prices in active markets.

The Company's other postretirement benefit plans' asset allocation at December 31, 2008 and 2007, and weighted average targeted asset allocation at December 31, 2008, were as follows:

Asset Category	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
	2008	2007	2008
Equity securities	60%	70%	70%
Fixed-income securities	34	27	30*
Other	6	3	---
Total	100%	100%	100%

* Includes target for both fixed-income securities and other.

The Company expects to contribute approximately \$12.4 million to its defined benefit pension plans and approximately \$3.3 million to its postretirement benefit plans in 2009.

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

Years	Pension Benefits	Other Postretirement Benefits
	<i>(In thousands)</i>	
2009	\$19,322	\$6,085
2010	20,018	6,278
2011	20,572	6,554
2012	21,543	6,738
2013	22,467	7,029
2014 - 2018	126,831	38,449

The following Medicare Part D subsidies are expected: \$700,000 in 2009; \$700,000 in 2010; \$800,000 in 2011; \$800,000 in 2012; \$800,000 in 2013; and \$5.1 million during the years 2014 through 2018.

In addition to company-sponsored plans, certain employees are covered under multi-employer pension plans administered by a union. Amounts contributed to the multi-employer plans were \$73.1 million, \$51.5 million and \$57.6 million in 2008, 2007 and 2006, 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 \$56.3 million at December 31, 2008, consisting of equity securities of \$25.1 million, life insurance carried on plan participants (payable upon the employee's death) of \$28.5 million, fixed-income securities of \$2.6 million, and other investments of \$100,000, which the Company anticipates using to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was \$9.0 million, \$7.6 million and \$7.5 million in 2008, 2007 and 2006, respectively. The total projected benefit obligation for these plans was \$87.2 million and \$80.6 million at December 31, 2008 and 2007, respectively. The accumulated benefit obligation for these plans was \$77.3 million and \$69.3 million at December 31, 2008 and 2007, respectively. A discount rate of 6.25 percent and 6.00 percent at December 31, 2008 and 2007, respectively, and a rate of compensation increase of 4.00 percent and 4.25 percent at December 31, 2008 and 2007, respectively, were used to determine benefit obligations. A discount rate of 6.00 percent and 5.75 percent at December 31, 2008 and 2007, respectively, and a rate of compensation increase of 4.25 percent at December 31, 2008 and 2007, 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 \$3.9 million in 2009; \$4.4 million in 2010; \$4.8 million in 2011; \$5.2 million in 2012; \$5.7 million in 2013; and \$34.8 million for the years 2014 through 2018.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were \$23.8 million in 2008, \$21.1 million in 2007 and \$17.3 million in 2006. The costs incurred in each year reflect additional participants as a result of business acquisitions.

SFAS No. 158 became effective for the Company as of December 31, 2006. The adoption resulted in a negative transition effect on accumulated other comprehensive loss of \$18.5 million.

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NOTE 18 - JOINTLY OWNED FACILITIES

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

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

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

	2008	2007
	<i>(In thousands)</i>	
Big Stone Station:		
Utility plant in service	\$61,030	\$61,568
Less accumulated depreciation	39,473	39,168
	\$21,557	\$22,400
Coyote Station:		
Utility plant in service	\$127,151	\$125,826
Less accumulated depreciation	82,018	79,783
	\$45,133	\$46,043

NOTE 19 - REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

On August 20, 2008, Montana-Dakota filed an application with the WYPSC for an electric rate increase. Montana-Dakota requested a total increase of \$757,000 annually or approximately 4 percent above current rates. A hearing before the WYPSC is scheduled for April 7, 2009. An order is anticipated in the second quarter of 2009.

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. Hearings on the application were held in June 2007. In September 2007, Montana-Dakota informed the NDPSC that certain of the other participants in the project had withdrawn and it was considering the impact of these withdrawals on the project and its options. Supplemental hearings before the NDPSC were held in late April 2008 regarding possible plant configuration changes as a result of the participant withdrawals and updated supporting modeling. On August 27, 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. On September 26, 2008, the intervenors in the proceeding appealed the NDPSC order to the North Dakota District Court. The appeal was assigned and a briefing schedule was established. The intervenors brief was filed January 16, 2009, and Montana-Dakota's brief is due in February 2009.

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. Currently, the only remaining issue outstanding related to this rate change application is in regard to certain service restrictions. In May 2004, the FERC remanded this issue to an ALJ for resolution. In November 2005, the FERC issued an Order on Initial Decision affirming the ALJ's Initial Decision regarding certain service and annual demand quantity restrictions. In April 2006, the FERC issued an Order on Rehearing denying Williston Basin's Request for Rehearing of the FERC's Order on Initial Decision. In April 2006, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision and its Order on Rehearing. On March 18, 2008, the D.C. Appeals Court issued its opinion in this matter concerning the service restrictions. The D.C. Appeals Court found that the FERC was correct to decide the case under the "just and

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reasonable" standard of section 5(a) of the Natural Gas Act; however, it remanded the case back to the FERC as flaws in the FERC's reasoning render its orders arbitrary and capricious. On December 18, 2008, the FERC issued its Order Requesting Data and Comment on this matter. Williston Basin and Northern States Power Company provided responses to FERC's requests in January 2009. In addition, initial comments addressing specific issues identified by the FERC are due to be filed by February 15, 2009, with reply comments due by March 7, 2009. The initial and reply comments should contain all the arguments and supporting evidence the parties determine they need to provide to update the record with regard to the issue under remand.

NOTE 20 - COMMITMENTS AND CONTINGENCIES

Litigation

Coalbed Natural Gas Operations Fidelity is a party to and/or certain of its operations are or have been the subject of more than a dozen lawsuits in Montana and Wyoming in connection with Fidelity's CBNG development in the Powder River Basin. The lawsuits generally involve either challenges to regulatory agency decisions under the NEPA or the MEPA or to Fidelity's management of water produced in association with its operations.

Challenges to State/Federal Regulatory Agency Decision Making Under NEPA/MEPA

In 1999 and 2000, the BLM, the Montana BOGC, and the Montana DEQ announced their respective decisions to prepare an EIS analyzing CBNG development in Montana. In 2003, the agencies each signed RODs approving a final EIS and allowing CBNG development throughout the State of Montana. The approval actions by the agencies resulted in numerous lawsuits initiated by environmental groups and the Northern Cheyenne Tribe related to the validity of the final EIS and associated environmental assessments. Fidelity has intervened in several of these lawsuits to protect its interests.

In lawsuits filed in Montana Federal District Court in May 2003, the NPRC and the Northern Cheyenne Tribe asserted that the BLM violated NEPA and other federal laws when approving the 2003 EIS. As a result of an order entered in those lawsuits, producers, including Fidelity, were allowed to engage in limited CBNG development of up to 500 CBNG wells to be drilled annually on private, state, and federal lands in the Montana Powder River Basin pending the BLM's preparation and adoption of a SEIS. As provided in the order, the injunction limiting development expired on January 14, 2009.

In December 2006, the BLM issued a draft SEIS that endorsed a phased-development approach to CBNG production in the Montana Powder River Basin, whereby future projects would be reviewed against four screens or filters (relating to water quality, wildlife, Native American concerns and air quality). Fidelity filed written comments on the draft SEIS asking the BLM to reconsider its proposed phased-development approach and to make numerous other changes to the draft SEIS. The final SEIS was released on October 31, 2008, and the related ROD was signed December 30, 2008. The final SEIS adopted a phased approach that is intended to reduce the overall cumulative impacts to any resource by managing the pace and place as well as the density and intensity of federal CBNG development. Among other limitations, the final SEIS includes a requirement to collect additional habitat data in order for the BLM to permit development in sage grouse crucial habitat areas. Fidelity believes that while permitting may be slower under the final SEIS, it should still be able to develop its CBNG resources at a pace sufficient to meet its investment objectives.

In a related action filed in Montana Federal District Court in December 2003, the NPRC asserted, among other things, that the actions of the BLM in approving Fidelity's applications for permits and the plan of development for the Badger Hills Project in Montana did not comply with applicable federal laws, including the NEPA. As a result of the litigation, Fidelity is operating under an Order, based on a stipulation between the parties, that allows production from existing wells in Fidelity's Badger Hills Project to continue pending preparation of a revised environmental analysis. Fidelity does not believe the revised environmental analysis will have a material impact on its operations. While Fidelity anticipates the revised environmental analysis will be tiered to the final SEIS, Fidelity does not anticipate the revised environmental analysis will impact existing

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development. With regard to future development, Fidelity's plans to drill in the Badger Hills Project are limited, and, as noted above, Fidelity believes it will be able to develop its CBNG resources at a pace sufficient to meet its investment objectives.

Cases Involving Fidelity's Management of Water Produced in Association with Its Operations
About half the CBNG cases Fidelity is involved in relate to administrative agency regulation of water produced in association with CBNG development in Montana and Wyoming. These cases involve legal challenges to the issuance of discharge permits, as well as challenges to the State of Wyoming's CBNG water permitting procedures.

In April 2006, the Northern Cheyenne Tribe filed a complaint in Montana State 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 December 9, 2008, the Montana State 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. Any appeal must be filed by March 23, 2009.

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.

The Powder River Basin Resource Council is funding litigation, filed in Wyoming State District Court in June 2007, on behalf of two surface owners against the Wyoming State Engineer and the Wyoming Board of Control. The plaintiffs seek a declaratory judgment that current ground water permitting practices are unlawful; that the state is required to adopt rules and procedures to ensure that coalbed groundwater is managed in accordance with the Wyoming Constitution and other laws; and that would prohibit the Wyoming State Engineer from issuing permits to produce coalbed groundwater and permits to store coalbed groundwater in reservoirs until the Wyoming State Engineer adopts such rules. The Wyoming State District Court granted the Petroleum Association of Wyoming's motion to intervene provided that the defendants motion to dismiss was denied. Fidelity is partly funding the intervention. On May 29, 2008, the Wyoming State District Court dismissed the case. The plaintiffs appealed to the Wyoming Supreme Court on June 27, 2008. Fidelity's CBNG operations in Wyoming could be materially adversely affected if the plaintiffs are successful in this lawsuit.

Fidelity will continue to vigorously defend its interests in all CBNG-related litigation in which it is involved, including the proceedings challenging its water permits. In those cases where damage claims have been asserted, Fidelity is unable to quantify the damages sought and will be unable to do so until after the completion of discovery. 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.

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Electric Operations Montana-Dakota joined with two electric generators in appealing a September 2003 finding by the ND Health Department that it may unilaterally revise operating permits previously issued to electric generating plants. Although it is doubtful that any revision of Montana-Dakota's operating permits by the ND Health Department would reduce the amount of electricity its plants could generate, the finding, if allowed to stand, could increase costs for sulfur dioxide removal and/or limit Montana-Dakota's ability to modify or expand operations at its North Dakota generation sites. Montana-Dakota and the other electric generators filed their appeal of the order in October 2003 in the North Dakota District Court. Proceedings were stayed pending conclusion of the periodic review of sulfur dioxide emissions in the state.

In September 2005, the ND Health Department issued its final periodic review decision based on its August 2005 final air quality modeling report. The ND Health Department concluded there were no violations of the sulfur dioxide increment in North Dakota. In March 2006, the DRC filed a complaint in Colorado Federal District Court seeking to force the EPA to declare that the increment had been violated based on earlier modeling conducted by the EPA. The EPA defended against the DRC claim and filed a motion to dismiss the case. The Colorado Federal District Court has dismissed the case.

In June 2007, the EPA noticed for public comment a proposed rule that would, among other things, adopt PSD increment modeling refinements that, if adopted, would operate to formally ratify the modeling techniques and conclusions contained in the September 2005 ND Health Department decision and the August 2005 final report.

In December 2008, the EPA indicated that the increment modeling rule would not be finalized. Because the EPA's action does not alter the September 2005 final review decision of the ND Health Department, and because the DRC's 2006 complaint was dismissed, the Company has determined the September 2003 finding by the ND Health Department will not have a material adverse impact on the Company and it does not intend to pursue the appeal of that finding.

On June 10, 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 alleges certain violations of the PSD and NSPS provisions of the Clean Air Act and certain violation of the South Dakota SIP. The action further alleges 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 alleges that these actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club seeks both 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 seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes that these 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. The ultimate outcome of these matters cannot be determined at this time.

Natural Gas Storage Based on reservoir and well pressure data and other information, Williston Basin believes that reservoir pressure (and therefore the amount of gas) in the EBSR, one of its natural gas storage reservoirs, has decreased as a result of Howell and Anadarko's drilling and production activities in areas within and near the boundaries of the EBSR. As of December 31, 2008, Williston Basin estimated that between 11.0 and 11.5 Bcf of storage gas had been diverted from the EBSR as a result of Howell and Anadarko's drilling and production.

Williston Basin filed suit in Montana Federal District Court in January 2006, seeking to recover unspecified damages from Howell and Anadarko, and to enjoin Howell and Anadarko's present and future production from specified wells in and near the EBSR. The Montana

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Federal District Court entered an Order in July 2006, dismissing the case for lack of subject matter jurisdiction. Williston Basin appealed and on May 9, 2008, the Ninth Circuit affirmed the Montana Federal District Court's decision.

In related litigation, Howell filed suit in Wyoming State District Court against Williston Basin in February 2006 asserting that it is entitled to produce any gas that might escape from the EBSR. In August 2006, Williston Basin moved for a preliminary injunction to halt Howell and Anadarko's production in and near the EBSR. The Wyoming State District Court denied Williston Basin's motion in July 2007. In December 2007, motions were argued to a court appointed special master concerning the application of certain legal principles to the production of Williston Basin's storage gas, including gas residing outside the certificated boundaries of the EBSR, by Howell and Anadarko. On March 17, 2008, the special master issued recommendations to the Wyoming State District Court. The special master recommended that the Wyoming State District Court adopt a ruling that gas injected into an underground reservoir belongs to the injector and the injector does not lose title to that gas unless the gas escapes or migrates from the reservoir because it was not well defined or well maintained or if the injector is unable to identify such injected gas because it has been commingled with native gas. The special master also recommended that the Wyoming State District Court adopt a ruling that generally would allow Howell and Anadarko to produce native gas residing inside or outside the certificated boundaries of the EBSR from its wells completed outside the certificated boundaries. The special master recognized that there are other issues yet to be developed that may be determinative of whether Howell and Anadarko may produce native or injected gas, or both. On July 1, 2008, the Wyoming State District Court adopted the special master's report. On July 16, 2008, Williston Basin filed a petition requesting the Wyoming Supreme Court to review a ruling by the Wyoming State District Court that the Natural Gas Act does not preempt the state law that permits an oil and gas producer to take gas that has been dedicated for use in a federally certificated gas storage reservoir. On August 5, 2008, the Wyoming Supreme Court denied the petition. The Wyoming State District Court has scheduled the case for trial beginning January 19, 2010.

In a related proceeding, the FERC issued an order on July 18, 2008, in response to a petition filed by Williston Basin on April 24, 2008, declaring that the certification of a storage facility under the Natural Gas Act conveys to the certificate holder the right to acquire native gas within the certificated boundaries of the storage facility. The FERC also concurred that state law precluding the certificate holder from acquiring the right to native gas would be preempted by federal law.

As previously noted, Williston Basin estimates that as of December 31, 2008, Howell and Anadarko had diverted between 11.0 and 11.5 Bcf from the EBSR. Although all of Howell's wells are shut in and no longer producing gas, Williston Basin believes that its gas losses from the EBSR will continue until pressures in the various interconnected geologic formations equalize. Williston Basin continues to monitor and analyze the situation. At trial, Williston Basin will seek recovery based on the amount of gas that has been and continues to be diverted as well as on the amount of gas that must be recovered as a result of the equalization of the pressures of various interconnected geological formations.

Expert reports were filed with the Wyoming State District Court in January 2008. Supplemental and rebuttal expert reports were filed September 15, 2008. Williston Basin's experts are of the opinion that all of the gas produced by Howell and Anadarko is Williston Basin's gas and will have to be replaced. Williston Basin's experts estimate that the replacement cost of the gas produced by Howell and Anadarko through July 2008 is approximately \$103 million if injection is completed by the end of the 2010 injection season. Williston Basin's experts also estimate that Williston Basin will expend \$6.3 million to mitigate the damages that Williston Basin suffered during the period of Howell and Anadarko's production if the replacement gas is injected by the end of the 2010 injection season. Williston Basin believes that its experts' opinions are based on sound law, economics, reservoir engineering, geology and geochemistry. The expert reports filed

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by Howell and Anadarko claim that storage gas owned by Williston Basin has migrated outside the EBSR into areas in which Howell and Anadarko have oil and gas rights. They theorize that Williston Basin is accountable to Howell and Anadarko for the migration of such gas. Although Howell and Anadarko have not specified the amount of damages they seek to recover, Williston Basin believes Howell and Anadarko's proposed methodology for valuing their alleged injury, if any, is flawed, inconsistent and lacking in factual and legal support.

Williston Basin intends to vigorously defend its rights and interests in these proceedings, to assess further avenues for recovery through the regulatory process at the FERC, and to pursue the recovery of any and all economic losses it may have suffered. Williston Basin cannot predict the ultimate outcome of these proceedings.

In light of the actions of Howell and Anadarko, Williston Basin installed temporary compression at the site in 2006 in order to maintain deliverability into the transmission system. Williston Basin leased working gas for the 2007 - 2008 and 2008 - 2009 heating seasons to supplement its cushion gas. While installation of the additional compression and leasing working gas provide temporary relief, Williston Basin believes that the adverse physical and operational effects occasioned by the past and potential future loss of storage gas could threaten the operation and viability of the EBSR, impair Williston Basin's ability to comply with the EBSR certificated operating requirements mandated by the FERC and adversely affect Williston Basin's ability to meet its contractual storage and transportation service commitments to customers. In another effort to protect the viability of the EBSR, Williston Basin, on April 18, 2008, filed an application with the FERC to expand the boundaries of the EBSR. The proposed expansion includes the areas from which Howell and Anadarko are producing.

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. Although the LWG originally estimated the overall remedial investigation and feasibility study would cost approximately \$10 million, it is now anticipated, on the basis of costs incurred to date and delays attributable to an additional round of sampling and potential further investigative work, that such cost could increase to a total in excess of \$60 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 record of decision has been published. The development of a proposed plan and ROD on the harbor site is not anticipated to occur until 2010, after which corrective action will be undertaken. 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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addition, MBI has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for any and all 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 limitation in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study.

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. It is not known at this time what share of the cleanup costs will actually be borne by Cascade. Additional ecological risk assessment conducted by Cascade and other PRPs is expected to be completed in 2009. The results of the assessment may affect the selection and implementation of a cleanup alternative.

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 that will require further investigation and cleanup. A supplemental investigation is currently being conducted to better characterize the extent of the contamination. The supplemental investigation is expected to be completed in 2009. The data from the preliminary investigation indicates other current and former owners of properties and businesses in the vicinity of the site may also be responsible for the contamination. There is currently not enough information to estimate the potential liability 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, 2008, were \$22.2 million in 2009, \$18.2 million in 2010, \$14.0 million in 2011, \$10.2 million in 2012, \$8.8 million in 2013 and \$42.2 million thereafter. Rent expense was \$35.3 million, \$35.6 million and \$23.1 million for the years ended December 31, 2008, 2007 and 2006, 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 one to 52 years. The commitments under these contracts as of December 31, 2008, were \$662.2 million in 2009, \$332.6 million in 2010, \$269.4 million in 2011, \$136.0 million in 2012, \$90.5 million in 2013 and \$268.1 million thereafter. Amounts purchased under various commitments for the years ended December 31,

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2008, 2007 and 2006, were approximately \$1.0 billion (including the acquisition of Intermountain as discussed in Note 2), \$857.0 million (including the acquisition of Cascade as discussed in Note 2) and \$265.8 million, respectively. These commitments were not reflected in the Company's consolidated financial statements.

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 continues to guarantee CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. As described in Note 3, Centennial Resources sold CEM in July 2007 to Bicent Power LLC, which has provided a \$10 million bank letter of credit to Centennial in support of that guarantee obligation. The guarantee, which has no fixed maximum, expires when CEM has completed its obligations under the construction contract. The warranty period associated with this project will expire one year after the date of substantial completion of construction. CEM declared substantial completion of the plant on February 16, 2009, and 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. LPP did not quantify the amount of indemnification being sought, which could be material. The Company believes that the indemnification claims are without merit and intends to vigorously defend against such claims.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements at December 31, 2008, expire in the years ranging from 2009 to 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 was no amount outstanding by Fidelity at December 31, 2008. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts, a conditional purchase agreement and certain other guarantees. At December 31, 2008, the fixed maximum amounts guaranteed under these agreements aggregated \$221.7 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate \$185.6 million in 2009; \$1.8 million in 2010; \$25.0 million in 2011; \$2.3 million in 2012; \$800,000 in 2013; \$1.2 million in 2018; \$1.0 million, which is subject to expiration 30 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 \$1.5 million and was reflected on the Consolidated Balance Sheet at December 31, 2008. 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

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December 31, 2008, the fixed maximum amounts guaranteed under these letters of credit, which expire in 2009, aggregated \$36.8 million. There were no amounts outstanding under the above letters of credit at December 31, 2008.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands. At December 31, 2008, the fixed maximum amounts guaranteed under these agreements aggregated \$24.0 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate \$20.0 million in 2009 and \$4.0 million in 2011. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was \$1.8 million, which was not reflected on the Consolidated Balance Sheet at December 31, 2008, 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, 2008.

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, 2008, approximately \$475 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2008

	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	\$3,996,948	\$4,372,226	9.39%
7				
8	TOTAL Intangible Plant	\$3,996,948	\$4,372,226	9.39%
9				
10	Production Plant			
11				
12	Steam Production			
13				
14	310 Land & Land Rights	\$251,583	\$255,125	1.41%
15	311 Structures & Improvements	11,940,988	12,409,159	3.92%
16	312 Boiler Plant Equipment	39,333,714	40,116,492	1.99%
17	313 Engines & Engine Driven Generators			
18	314 Turbogenerator Units	11,073,165	11,277,231	1.84%
19	315 Accessory Electric Equipment	3,363,030	3,709,541	10.30%
20	316 Miscellaneous Power Plant Equipment	3,768,463	3,928,160	4.24%
21				
22	TOTAL Steam Production Plant	\$69,730,943	\$71,695,708	2.82%
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			
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			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2008

	Account Number & Title	Last Year	This Year	% Change
1				
2	Production Plant (cont.)			
3				
4	Other Production			
5				
6	340 Land & Land Rights	\$16,431	\$16,663	1.41%
7	341 Structures & Improvements	111,867	196,918	76.03%
8	342 Fuel Holders, Producers & Accessories	150,661	153,984	2.21%
9	343 Prime Movers			
10	344 Generators	7,784,199	16,482,089	111.74%
11	345 Accessory Electric Equipment	218,603	232,135	6.19%
12	346 Miscellaneous Power Plant Equipment	12,203	13,889	13.82%
13				
14	TOTAL Other Production Plant	\$8,293,964	\$17,095,678	106.12%
15				
16	TOTAL Production Plant	\$78,024,907	\$88,791,386	13.80%
17				
18	Transmission Plant			
19				
20	350 Land & Land Rights	\$661,634	\$684,646	3.48%
21	352 Structures & Improvements	442	448	1.36%
22	353 Station Equipment	18,012,392	17,337,267	-3.75%
23	354 Towers & Fixtures	1,078,440	1,198,577	11.14%
24	355 Poles & Fixtures	6,621,102	7,086,950	7.04%
25	356 Overhead Conductors & Devices	5,780,580	5,949,337	2.92%
26	357 Underground Conduit	0	312,249	100.00%
27	358 Underground Conductors & Devices	0	645,375	100.00%
28	359 Roads & Trails			
29				
30	TOTAL Transmission Plant	\$32,154,590	\$33,214,849	3.30%
31				
32	Distribution Plant			
33				
34	360 Land & Land Rights	\$262,141	\$265,747	1.38%
35	361 Structures & Improvements			
36	362 Station Equipment	5,246,340	5,883,351	12.14%
37	363 Storage Battery Equipment			
38	364 Poles, Towers & Fixtures	6,070,220	6,317,717	4.08%
39	365 Overhead Conductors & Devices	4,816,611	4,921,857	2.19%
40	366 Underground Conduit	12,967	12,967	0.00%
41	367 Underground Conductors & Devices	5,584,043	6,138,549	9.93%
42	368 Line Transformers	7,664,612	8,398,019	9.57%
43	369 Services	4,021,115	4,142,870	3.03%
44	370 Meters	2,545,619	2,814,544	10.56%
45	371 Installations on Customers' Premises	691,516	728,468	5.34%
46	372 Leased Property on Customers' Premises			
47	373 Street Lighting & Signal Systems	1,573,739	1,641,533	4.31%
48				
49	TOTAL Distribution Plant	\$38,488,923	\$41,265,622	7.21%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2008

	Account Number & Title	Last Year	This Year	% Change
1				
2	General Plant			
3				
4	389 Land & Land Rights	\$2,063	\$2,065	0.10%
5	390 Structures & Improvements	120,956	121,025	0.06%
6	391 Office Furniture & Equipment	197,189	206,032	4.48%
7	392 Transportation Equipment	1,053,735	1,193,427	13.26%
8	393 Stores Equipment	8,847	7,904	-10.66%
9	394 Tools, Shop & Garage Equipment	501,119	463,382	-7.53%
10	395 Laboratory Equipment	210,692	210,977	0.14%
11	396 Power Operated Equipment	2,168,387	2,449,842	12.98%
12	397 Communication Equipment	320,526	331,939	3.56%
13	398 Miscellaneous Equipment	19,809	19,855	0.23%
14	399 Other Tangible Property			
15				
16	TOTAL General Plant	\$4,603,323	\$5,006,448	8.76%
17				
18	Common Plant			
19				
20	389 Land & Land Rights	\$185,775	\$201,319	8.37%
21	390 Structures & Improvements	3,105,705	3,376,502	8.72%
22	391 Office Furniture & Equipment	1,097,851	897,762	-18.23%
23	392 Transportation Equipment	1,027,975	1,254,750	22.06%
24	393 Stores Equipment	11,031	11,180	1.35%
25	394 Tools, Shop & Garage Equipment	198,425	206,247	3.94%
26	395 Laboratory Equipment			
27	396 Power Operated Equipment	520	526	1.15%
28	397 Communication Equipment	257,703	305,014	18.36%
29	398 Miscellaneous Equipment	101,631	112,454	10.65%
30	399 Other Tangible Property			
31				
32	TOTAL Common Plant	\$5,986,616	\$6,365,754	6.33%
33				
34				
35	TOTAL Electric Plant in Service	\$163,255,307	\$179,016,285	9.65%

MONTANA DEPRECIATION SUMMARY

Year: 2008

	Functional Plant Classification	Plant Cost	Accumulated Depreciation		Current Avg. Rate
			Last Year Bal.	This Year Bal.	
1					
2	Steam Production 1/	\$75,616,779	\$56,409,272	\$58,818,491	3.58%
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production	17,095,678	2,638,265	3,231,501	3.27%
6	Transmission	33,214,849	17,164,656	17,825,555	1.78%
7	Distribution	41,265,622	21,626,736	22,358,116	2.96%
8	General	6,394,879	3,034,671	3,432,689	2.89%
9	Common	9,349,549	4,728,150	5,181,577	5.00%
10	TOTAL	\$182,937,356	\$105,601,750	\$110,847,929	3.13%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	\$1,142,819	\$1,158,049	1.33%
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)	508,645	547,790	7.70%
9	Transmission Plant (Estimated)	299,707	307,284	2.53%
10	Distribution Plant (Estimated)	768,474	763,158	-0.69%
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	\$2,719,645	\$2,776,281	2.08%

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	46.706%	10.250%	4.787%
13	Preferred Stock	2.737%	4.599%	0.126%
14	Long Term Debt	41.144%	6.868%	2.826%
15	Short Term Debt	9.413%	3.558%	0.335%
16	TOTAL	100.000%		8.074%

STATEMENT OF CASH FLOWS

Year: 2008

	Description	Last Year 1/	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	Cash Flows from Operating Activities:			
4	Net Income	\$432,120,349	\$293,673,229	-32.04%
5	Depreciation	32,223,579	34,040,420	5.64%
6	Amortization	689,959	316,354	-54.15%
7	Deferred Income Taxes - Net	496,230	19,761,591	3882.35%
8	Investment Tax Credit Adjustments - Net	(355,732)	(248,195)	-30.23%
9	Change in Operating Receivables - Net	(1,449,017)	3,271,846	325.80%
10	Change in Materials, Supplies & Inventories - Net	10,086,658	8,217,051	-18.54%
11	Change in Operating Payables & Accrued Liabilities - Net	17,597,389	(34,470,080)	-295.88%
12	Change in Other Regulatory Assets	(4,000,748)	2,019,006	150.47%
13	Change in Other Regulatory Liabilities	(1,329,929)	(781,318)	41.25%
14	Allowance for Other Funds Used During Construction (AFUDC)	(1,230,086)	(119,056)	-90.32%
15	Change in Other Assets & Liabilities - Net	1,444,319	(13,303,075)	-1021.06%
16	Less Undistributed Earnings from Subsidiary Companies	(308,882,963)	(171,164,580)	-44.59%
17	Other Operating Activities (explained on attached page)			
18	Net Cash Provided by/(Used in) Operating Activities	\$177,410,008	\$141,213,193	-20.40%
19				
20	Cash Inflows/Outflows From Investment Activities:			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	(\$123,490,086)	(\$105,520,724)	-14.55%
23	Acquisition of Other Noncurrent Assets	(3,097,384)	5,940,589	-291.79%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(290,177,157)	(172,005,700)	-40.72%
26	Contributions and Advances from Affiliates	281,230,210	121,000,000	-56.97%
27	Disposition of Investments in and Advances to Affiliates	0	0	0.00%
28	Other Investing Activities: Depreciation & RWIP on Nonutility Plant	102,657	122,650	19.48%
29	Net Cash Provided by/(Used in) Investing Activities	(\$135,431,760)	(\$150,463,185)	11.10%
30				
31	Cash Flows from Financing Activities:			
32	Proceeds from Issuance of:			
33	Long-Term Debt	\$35,250,000	\$100,508,867	185.13%
34	Preferred Stock			
35	Common Stock	17,263,199	15,011,178	-13.05%
36	Other:	0	57,000,000	100.00%
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper			
39	Payment for Retirement of:			
40	Long-Term Debt	(6,600,000)	(53,600,000)	712.12%
41	Preferred Stock			
42	Common Stock			
43	Other: Adjustment to Retained Earnings	(159,988)	(44,761)	72.02%
44	Net Decrease in Short-Term Debt			
45	Dividends on Preferred Stock	(685,004)	(685,004)	0.00%
46	Dividends on Common Stock	(101,969,421)	(109,925,942)	7.80%
47	Other Financing Activities (explained on attached page)			
48	Net Cash Provided by (Used in) Financing Activities	(\$56,901,214)	\$8,264,338	114.52%
49				
50	Net Increase/(Decrease) in Cash and Cash Equivalents	(\$14,922,966)	(\$985,654)	-93.40%
51	Cash and Cash Equivalents at Beginning of Year	\$18,142,124	\$3,219,158	-82.26%
52	Cash and Cash Equivalents at End of Year	\$3,219,158	\$2,233,504	-30.62%

1/ Last year's information has been restated to reflect a change in reporting common stock information in the FERC Form 1, to align with GAAP reporting principles.

LONG TERM DEBT

Year: 2008

	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	8.60 % Secured MTN, Series A	04/92	04/12	\$35,000,000	\$28,906,532	\$4,500,000	8.60%	\$495,900	11.02%
2	6.71 % Secured MTN, Series A	09/97	10/09	15,000,000	13,488,404	1,000,000	6.71%	81,950	8.20%
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%
6									
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8									
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22									
23									
24									
25									
26	TOTAL			\$280,000,000	\$260,613,266	\$235,500,000		\$16,134,350	6.85%

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

PREFERRED STOCK

Year: 2008

	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%	700,000	36,995	5.29%
4										
5										
6										
7										
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28										
29										
30										
31										
32	TOTAL					\$19,947,548		\$15,700,000	\$721,995	4.60%

1/ Plus accrued dividends.

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

Year: 2008

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									
2									
3									
4	January								
5									
6	February								
7									
8	March	182,598,541	\$13.82	\$0.39	\$0.1450	62.82%	\$27.83	\$23.08	9.9 X
9									
10	April								
11									
12	May								
13									
14	June	182,972,402	14.06	0.63	0.1450	76.98%	35.25	24.70	13.3 X
15									
16	July								
17									
18	August								
19									
20	September	183,219,359	15.14	0.65	0.1550	76.15%	35.34	26.03	13.4 X
21									
22	October								
23									
24	November								
25									
26	December	183,603,463	14.95	(0.06)	0.1550	358.33%	29.50	15.50	13.6 X
27									
28									
29									
30	TOTAL Year End	183,100,152	\$14.95	\$1.61	0.6000	62.73%			13.6 X

1/ Basic shares

2/ Basic earnings per share.

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

MONTANA EARNED RATE OF RETURN

Year: 2008

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service 1/	\$164,743,296	\$180,335,823	9.46%
3	108 (Less) Accumulated Depreciation 2/	103,423,419	108,535,171	4.94%
4				
5	NET Plant in Service	\$61,319,877	\$71,800,652	17.09%
6				
7	CWIP in Service Pending Reclassification	\$611,372	\$618,108	1.10%
8				
9	Additions			
10	151 Fuel Stocks	\$1,142,819	\$1,158,049	1.33%
11	154, 156 Materials & Supplies	1,576,826	1,618,232	2.63%
12	165 Prepayments	27,110	28,148	3.83%
13	Other Additions			
14				
15	TOTAL Additions	\$2,746,755	\$2,804,429	2.10%
16				
17	Deductions			
18	190 Accumulated Deferred Income Taxes	\$8,586,644	\$11,510,738	34.05%
19	252 Customer Advances for Construction	410,524	488,748	19.05%
20	255 Accumulated Def. Investment Tax Credits	144,672	73,752	-49.02%
21	Other Deductions			
22				
23	TOTAL Deductions	\$9,141,840	\$12,073,238	32.07%
24	TOTAL Rate Base	\$55,536,164	\$63,149,951	13.71%
25				
26	Net Earnings	\$1,189,496	\$5,092,091	328.09%
27				
28	Rate of Return on Average Rate Base	2.28%	8.58%	276.32%
29				
30	Rate of Return on Average Equity	-1.82%	11.13%	711.54%
31				
32	Major Normalizing Adjustments & Commission			
33	<u>Ratemaking adjustments to Utility Operations 3/</u>			
34				
35	<u>Adjustment to Operating Revenues</u>			
36	Late Payment Revenues	\$10,819	\$14,172	30.99%
37	Gain from Disposition of Property 4/	3,321	3,302	-0.57%
38				
39	<u>Adjustment to Operating Expenses</u>			
40	Elimination of Promotional & Institutional Advertising	(12,890)	(8,623)	33.10%
41	Elimination of Supplemental Insurance	(89,063)	(389,181)	-336.97%
42	Elimination of 401K Tax Deduction 5/	149,899	148,101	-1.20%
43				
44	Total Adjustments to Operating Income	(\$33,806)	\$267,177	-890.31%
45				
46				
47	Adjusted Rate of Return on Average Rate Base	2.21%	9.03%	308.60%
48				
49	Adjusted Rate of Return on Average Equity	-1.95%	12.05%	717.95%

1/ Excludes Acquisition Adjustment of \$2,565,403 for 2007 and \$2,601,533 for 2008.

2/ Excludes Acquisition Adjustment of \$2,178,331 for 2007 and \$2,312,758 for 2008.

3/ Updated amounts, net of taxes.

4/ Amortized over 5 years.

5/ Restated 2007 to include adjustment for 401K tax deduction.

MONTANA COMPOSITE STATISTICS

Year: 2008

	Description	Amount
1		
2	Plant (Intrastate Only) (000 Omitted)	
3		
4	101 Plant in Service	\$177,798
5	107 Construction Work in Progress	8,785
6	114 Plant Acquisition Adjustments	
7	105 Plant Held for Future Use	
8	154, 156 Materials & Supplies	1,618
9	(Less):	
10	108, 111 Depreciation & Amortization Reserves	108,535
11	252 Contributions in Aid of Construction	489
12		
13	NET BOOK COSTS	\$79,177
14		
15	Revenues & Expenses (000 Omitted)	
16		
17	400 Operating Revenues	\$47,668
18		
19	403 - 407 Depreciation & Amortization Expenses	\$5,731
20	Federal & State Income Taxes	1,299
21	Other Taxes	3,184
22	Other Operating Expenses	32,362
23	TOTAL Operating Expenses	\$42,576
24		
25	Net Operating Income	\$5,092
26		
27	Other Income	345
28	Other Deductions	1,971
29		
30	NET INCOME	\$3,466
31		
32	Customers (Intrastate Only)	
33		
34	Year End Average:	
35	Residential	18,338
36	Small General	5,259
37	Large General	251
38	Other	191
39		
40	TOTAL NUMBER OF CUSTOMERS	24,039
41		
42	Other Statistics (Intrastate Only)	
43		
44	Average Annual Residential Use (Kwh))	8,657
45	Average Annual Residential Cost per (Kwh) (Cents) * 1/	\$0.084
46	* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47	Average Residential Monthly Bill	\$60.60
48	Gross Plant per Customer	\$7,396

1/ Reflects average revenue for 2008.

MONTANA CUSTOMER INFORMATION

Year: 2008

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Antelope	43	52	15	2	69
2	Bainville	153	99	44	6	149
3	Baker	1,695	957	337	13	1,307
4	Brockton	245	100	23	3	126
5	Carlyle	Not Available	2	5		7
6	Culbertson	716	335	140	4	479
7	Fallon	138	171	88	1	260
8	Fairview	709	389	92	3	484
9	Flaxville	87	53	25	3	81
10	Forsyth	1,944	1,025	277	10	1,312
11	Froid	195	135	45	4	184
12	Glendive	4,729	3,257	778	35	4,070
13	Homestead	Not Available	17	8	1	26
14	Ismay	26	23	17	1	41
15	Medicine Lake	269	163	51	4	218
16	Miles City	8,487	4,489	1,026	42	5,557
17	Outlook	82	50	35	12	97
18	Plentywood	2,061	940	257	6	1,203
19	Plevna	138	94	25	3	122
20	Poplar	911	875	169	15	1,059
21	Poplar Oil Field	Not Available		6	11	17
22	Redstone	Not Available	17	19	1	37
23	Reserve	37	25	13	3	41
24	Rosebud	Not Available	71	54	2	127
25	Savage	Not Available	135	31	2	168
26	Scobey	1,082	585	175	3	763
27	Sidney	4,774	2,321	481	24	2,826
28	Terry	611	354	104	10	468
29	Whitetail	Not Available	24	20	1	45
30	Wibaux	567	294	102	8	404
31	Wolf Point	2,663	1,465	340	10	1,815
32	Kinsey	Not Available	112	45	2	159
33	MT Oil Fields	Not Available	8	68	75	151
35	TOTAL Montana Customers	32,362	18,637	4,915	320	23,872

1/ 2000 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 2008

	Department	Year Beginning	Year End	Average
1	Electric	19	18	18.5
2	Gas	40(2)	42	41(1)
3	Accounting	18	19	18.5
4	Management	7	7	7
5	Service	52(3)	47(1)	49.5(2)
6	Communications/Substation/Training	5	4	4.5
7	Power Production	27	29	28
8				
9				
10				
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42				
43				
44	TOTAL Montana Employees	168(5)	166(1)	167(3)

1/ Parentheses denotes part-time.

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)**Year: 2008**

	Project Description	Total Company	Total Montana	
1	<u>Projects>\$1,000,000</u>			
2	<u>Common-Intangible</u>			
3	Replace Customer Information System	\$4,467,936	\$1,113,577	1/
4	<u>Electric-Steam Production</u>			
5	Purchase 25 MW of WYGEN III Power Plant	60,464,382	0	
6	Construct Big Stone II Power Plant	5,228,621	1,309,418	1/
7	Install Mercury Control System at Lewis & Clark Station	3,000,000	753,964	1/
8	Replace HP/IP Turbine at Coyote Station	1,545,741	387,123	1/
9	<u>Electric-Other Production</u>			
10	Install 30MW Wind Power in ND and MT	9,241,300	2,377,381	1/
11	Install Waste Heat Energy Converter near Glen Ullin, ND	7,570,969	1,895,915	1/
12	<u>Electric-Transmission</u>			
13	Install 120MVA Auto Transformer at Tioga, ND Substation	2,367,636	592,978	1/
14	<u>Electric-Distribution</u>			
15	Construct Distribution Substation in Bismarck, ND	1,214,136	0	
16	<u>Gas-Production</u>			
17	Install Gas Extraction Facility at Landfill in Billings, MT	1,428,000	400,370	1/
18				
19	<u>Other Projects<\$1,000,000</u>			
20	<u>Electric</u>			
21	Production	10,430,198	2,608,475	1/
22	Integrated Transmission	757,813	175,061	1/
23	Direct Transmission	590,789	122,825	2/
24	Distribution	11,843,375	2,106,269	2/
25	General	631,987	119,843	1/
26	Common:			
27	General Office	303,606	70,372	1/
28	Other Direct	60,517	8,335	2/
29	Total Electric	24,618,285	5,211,180	
30	<u>Gas</u>			
31	Distribution	10,277,643	3,091,421	1/
32	General	1,104,194	365,161	2/
33	Common:			
34	General Office	233,750	64,093	1/
35	Other Direct	26,461	7,211	2/
36	Total Gas	11,642,048	3,527,886	
37	TOTAL	\$132,789,054	\$17,569,792	

1/ Allocated to Montana.

2/ Directly assigned to Montana.

TOTAL INTEGRATED SYSTEM & MONTANA PEAK AND ENERGY

Year: 2008

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.	29	1900	407.3	262,437	6,054
2	Feb.	10	2000	400.4	234,557	15,850
3	Mar.	7	1000	369.0	243,201	26,472
4	Apr.	1	1000	326.9	240,517	43,053
5	May	16	1300	305.0	202,723	6,278
6	Jun.	30	1800	418.5	188,774	2,205
7	Jul.	30	1700	472.6	243,562	14,717
8	Aug.	20	1700	476.6	257,618	23,951
9	Sep.	18	1700	364.5	204,123	20,117
10	Oct.	28	900	351.4	239,629	42,594
11	Nov.	20	2000	377.9	235,519	18,922
12	Dec.	15	1900	455.0	271,110	3,565
13	TOTAL				2,823,770	223,778

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.	29	1900	89.0	Not Available	Not Available
15	Feb.	10	2000	102.1		
16	Mar.	7	1000	90.7		
17	Apr.	1	1000	82.9		
18	May	16	1300	80.0		
19	Jun.	30	1800	111.8		
20	Jul.	30	1700	115.2		
21	Aug.	20	1700	118.9		
22	Sep.	18	1700	85.8		
23	Oct.	28	900	87.4		
24	Nov.	20	2000	93.4		
25	Dec.	15	1900	115.6		
26	TOTAL					

TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	2,469,936	Sales to Ultimate Consumers (Include Interdepartmental)	2,663,452
3	Nuclear			
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales for Resale	
6	Other	68,503		
7	(Less) Energy for Pumping			
8	NET Generation	2,538,439	Non-Requirements Sales for Resale	223,778
9	Purchases	514,835		
10	Power Exchanges			
11	Received	29,318	Energy Furnished Without Charge	
12	Delivered	27,500		
13	NET Exchanges	1,818		
14	Transmission Wheeling for Other		Energy Used Within Electric Utility	
15	Received	1,620,503		
16	Delivered	1,521,991		
17	NET Transmission Wheeling	98,512	Total Energy Losses	230,911
18	Transmission by Others Losses	(35,463)		
19	TOTAL	3,118,141	TOTAL	3,118,141

Montana-Dakota's annual peak occurred during HE1700 August 20, 2008. All generation units were available for operation during the peak hour. The following units were on line and providing energy.

Heskett #1	18.4
Heskett #2	69.4
Lewis & Clark	41.3
Glendive Turbine	0.0
Coyote	103.0
Big Stone	106.0
Diamond Willow	0.5

Montana-Dakota also purchased 125.9 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: 2008

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Combustion Turbine	Williston Plant	Williston, ND	10.9	(79.7)
2	Combustion Turbine	Miles City Turbine	Miles City, MT	21.6	368.7
3	Thermal	Lewis & Clark Station	Sidney, MT	53.7	331,504.2
4	Combustion Turbine	Glendive Turbine	Glendive, MT	76.3	3,217.7
5	Thermal	Heskett Station	Mandan, ND	103.1	566,695.3
6	Thermal	Big Stone Station	Milbank, SD	109.0	826,737.4
7				(MDU SHARE)	
8	Thermal	Coyote Station	Beulah, ND	109.4	744,999.0
9				(MDU SHARE)	
10	Wind	Diamond Willow	Baker, MT	19.6	64,996.9
11					
12					
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41					
42					
43	Total			503.5	2,538,439.4

Outage Start Date/Time	Outage End Date/Time	Brief Description of Primary Cause	1/
<u>Big Stone Plant</u>			
01/04/2008 23:54	01/06/2008 03:35	Repair Generator Hydrogen Leak	
02/13/2008 05:42	02/13/2008 06:54	Unit Trip Due To FDFT Control Problems	
02/24/2008 01:07	02/24/2008 02:08	Operator Attempt To Abort Valve Test	
04/23/2008 00:29	04/25/2008 05:18	Leak In Cyclone #2	
05/21/2008 20:02	05/31/2008 01:26	Cold End Air Heater Basket Change	
08/06/2008 00:47	08/07/2008 02:21	Tube Leak	
08/07/2008 02:26	08/07/2008 03:57	High Drum Level	
09/15/2008 23:59	09/17/2008 07:53	BFP High Pressure Recirculation Valve	
11/08/2008 16:23	11/10/2008 07:22	Tube Leak	
<u>Coyote Station</u>			
01/06/2008 06:38	01/07/2008 08:14	Primary Superheat Tube Leak	
01/16/2008 21:01	01/18/2008 00:19	Reheat Tube Leak	
02/03/2008 17:56	02/05/2008 09:48	Wall Tube Leak	
02/20/2008 21:18	02/22/2008 01:18	Secondary Superheat Tube Leak	
03/07/2008 22:00	03/10/2008 17:26	Scheduled Wash Outage	
03/20/2008 22:04	03/21/2008 21:12	Primary Superheat Tube Leak	
04/30/2008 07:58	05/01/2008 18:39	#6 Cyclone Tube Leak	
06/05/2008 22:06	06/14/2008 08:55	Scheduled Spring Wash Outage	
06/19/2008 14:21	06/19/2008 16:11	Voltage Regulator Card Removed	
09/01/2008 20:39	09/04/2008 02:27	#1 Cyclone Tube Leak	
09/11/2008 22:19	09/15/2008 07:28	Scheduled Boiler Wash Outage	
12/01/2008 22:45	12/05/2008 09:19	Scheduled Wash Outage, Replace BCP "A"	
<u>Lewis & Clark Station</u>			
01/03/2008 13:04	01/05/2008 13:22	Split In A Boiler Tube	
04/04/2008 07:36	04/04/2008 12:49	Clean Scrubber Disk Area	
05/03/2008 02:33	05/20/2008 09:07	Planned Spring Outage	
08/30/2008 02:10	08/30/2008 07:16	480-Volt UPS Feed Failed	
09/26/2008 21:50	10/03/2008 08:52	Planned Fall Outage	

<u>Outage Start Date/Time</u>	<u>Outage End Date/Time</u>	<u>Brief Description of Primary Cause</u> 1/
<u>Heskett Unit 1</u>		
01/28/2008 07:50	02/01/2008 13:10	Platen Superheater Tube Leak
04/02/2008 16:09	04/08/2008 07:44	Boiler Screen Tubes Slagged Over
05/16/2008 22:12	05/25/2008 09:21	Maintenance Outage
06/15/2008 20:42	06/18/2008 01:08	Traveling Grate Chain Broke
09/20/2008 10:39	10/06/2008 19:51	North Traveling Grate Bound Up
10/06/2008 21:22	10/07/2008 19:20	North Drum Safety Valve Gasket Leak
11/14/2008 21:33	11/16/2008 05:48	Secondary Superheater Tube Leaks
<u>Heskett Unit 2</u>		
01/04/2008 00:05	01/11/2008 20:57	Maintenance Outage
03/27/2008 00:32	03/31/2008 11:24	Clean Out Bed Agglomerates
05/14/2008 01:07	05/25/2008 21:30	Maintenance Outage
05/25/2008 21:30	06/30/2008 07:30	Forced Draft Fan Vibration, Loose Fan Wheel
07/09/2008 09:23	07/09/2008 13:29	Unit Trip While Testing Alarms On Transformer
07/09/2008 13:29	07/12/2008 05:19	Bed Agglomeration
09/16/2008 20:16	09/21/2008 20:47	Clean Inbed Generating Tube Shields
10/13/2008 11:50	10/14/2008 16:55	Pin Hole Leak, LIP Extraction Steam Piping

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

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2008

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1							
2	MT Conservation & DSM Program	\$11,923	\$25,777	-53.75%	N/A	0.12 MWH	N/A
3	(As Detailed on Schedule 35B)						
4							
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30							
31							
32	TOTAL	\$11,923	\$25,777	-53.75%	N/A	0.12 MWH	N/A

ELECTRIC UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2008

	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	\$4,414	\$0	\$4,414	0.08 MWh	2008
3	Refrigerator Roundup	6,471	0	6,471	0.03 MWh	2008
4	High Efficiency Appliances	1,038	0	1,038	0.01 MWh	2008
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	\$105,037	\$0	\$105,037		2008
27						
28	Bill Assistance	80,000	0	80,000		2008
29						
30	Conservation	137,200	0	137,200		2008
31						
32	Furnace Safety	25,000	0	25,000		2008
33						
34	Education	1,800	0	1,800		2008
35	Large Customer Self Directed					
36		\$208,798	\$0	\$208,798		
37						
38						
39						
40						
41	Total	\$569,758	\$0	\$569,758	0.12	2008
42	Number of customers that received low income rate discounts (Average)				939	
43	Average monthly bill discount amount (\$/mo)				\$9.33	
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: 2008

	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	\$4,414	\$0	\$4,414	0.08	2008
3	Refrigerator Roundup	6,471	0	6,471	0.03	2008
4	High Efficiency Appliances	1,038	0	1,038	0.01	2008
5						
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8	Demand Response					
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15	Market Transformation					
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22	Research & Development					
23						
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25						
26						
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28						
29	Low Income					
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35	Other					
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45						
46	Total	\$11,923	\$0	\$11,923	0.12	2008

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 36

MONTANA CONSUMPTION AND REVENUES

Year: 2008

	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	\$13,286,405	\$11,661,380	158,744	158,917	18,338	18,289
2	Small General	8,005,129	6,750,592	109,843	110,384	5,259	5,216
3	Large General	20,981,552	17,245,513	408,810	385,234	251	253
4	Lighting	786,236	689,417	9,913	9,797	85	79
5	Municipal Pumping	387,237	320,805	7,034	6,828	106	105
6	Sales to Other Utilities	2,339,802	1,649,663	Not Applicable	Not Applicable	Not Applicable	Not Applicable
7							
8							
9							
10							
11							
12							
13	TOTAL	\$45,786,361	\$38,317,370	694,344	671,160	24,039	23,942