YEAR ENDING 2008

ANNUAL REPORT
OF

MONTANA-DAKOTA UTILITIES CO.

GAS UTILITY

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

REVISED 2005

2008 Gas 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. The use of the EXCEL© file 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 shall 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. If you elect not to use the disk, please format your reports to fit on one 8.5'' by 11'' page with the left binding edge (top if landscaped) set at .85'', the right edge (bottom if landscaped) set at .4'', and the remaining two margins at .5''

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
    Schedule 33

    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.

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

11. For schedules where information may be provided using Mcf or Dkt, circle Mcf or Dkt to indicate which measurement is being reported. (For example, schedules 28, 32, 33 and 34).

12. FERC Form-2 sheets may not be substituted in lieu of completing annual report schedules.

13. 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 201 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 and132 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

2. 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.)

3. 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 34

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 36a

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.

Gas Annual Report

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Company Name: Montana-Dakota Utilities Co. **SCHEDULE 1**

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.,	
9	and has no Board of Directors. The affairs of the Company are managed by	
10	a Managing Committee, the members of which are provided herein rather	
11	than the directors of MDU Resources Group, Inc.	
12		
13		
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16		
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18		

Officers

Year: 2008

Title of Officer (a)	Department Supervised (b)	Name (c)
President & Chief Executive Officer	Executive	David L. Goodin
Executive Vice President	Regulatory, Business Development and Gas Supply	Dennis L. Haider
Executive Vice President	Finance, Integration and Acquisitions	John F. Renner
Vice President	Regulatory Affairs	Donald R. Ball
Vice President	Electric Supply	Andrea L. Stomberg
Vice President	Operations	Jay Skabo
Vice President	Controller and Chief Accounting Officer	Garret Senger

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				
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22				
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48				
49				
50	**TOTAL**		$292,988	100.00%

CORPORATE ALLOCATIONS - GAS

Year: 2008

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$2,707	1.08%	$247,649
Advertising	Administrative & General	Various Corporate Overhead Allocation Factors, and/or Actual Costs Incurred	1,586	1.06%	148,277
Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,232	1.06%	115,038
Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	602	1.67%	35,432
Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3,746	1.07%	345,549
Computer Rental	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	295	2.65%	10,838
Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	22,175	1.92%	1,132,353
Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	36,822	1.57%	2,310,789
Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,600	1.22%	129,169
Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a Combination of Net Plant Investment and Number of Employees	10,413	0.76%	1,361,124
Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on Number of Employees	4,209	1.29%	320,902

CORPORATE ALLOCATIONS - GAS

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	2,164	0.96%	223,063
2			Actual Costs Incurred			
3						
4	Employee Reimbursable	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,813	1.29%	214,835
5	Expenses		Studies, and/or Actual Costs Incurred			
6						
7	Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	16,985	1.07%	1,574,770
8			Actual Costs Incurred			
9						
10	Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	41	1.41%	2,868
11			Studies, and/or Actual Costs Incurred			
12						
13	Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,095	1.18%	91,993
14			Studies, and/or Actual Costs Incurred			
15						
16	Moving Expense	Administrative & General	Various Corporate Overhead Allocation Factors and/or	148	0.93%	15,756
17			Actual Costs Incurred			
18						
19	Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,331	1.01%	129,878
20			Studies, and/or Actual Costs Incurred			
21						
22	Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or	2,371	1.77%	131,415
23			Actual Costs Incurred			
24						
25	Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and	16,485	0.99%	1,655,356
26			Allocation Factors Based on Actual Experience			
27						
28	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	441	1.48%	29,265
29			Actual Costs Incurred			

CORPORATE ALLOCATIONS - GAS

Year: 2008

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or	230	1.31%	17,273
2			Actual Costs Incurred			
3						
4	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time	272,623	1.37%	19,633,825
5			Studies, and/or Actual Costs Incurred			
6						
7	Reimbursements and	Administrative & General	Various Corporate Overhead Allocation Factors and/or	(2,306)	11.29%	(18,114)
8	Warranty Credits		Actual Costs Incurred			
9						
10	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or	130	1.81%	7,036
11			Actual Costs Incurred			
12						
13	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or	1,822	1.21%	148,590
14			Actual Costs Incurred			
15						
16	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,832	1.43%	126,030
17	Registrations		Studies, and/or Actual Costs Incurred			
18						
19	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	7,155	1.48%	476,071
20			Studies, and/or Actual Costs Incurred			
21						
22	Supplemental Insurance	Administrative & General	Various Corporate Overhead Allocation Factors	64,467	1.06%	6,003,955
23						
24	Telephone & Cell Phones	Administrative & General	Various Corporate Overhead Allocation Factors and/or	2,558	1.14%	221,484
25			Actual Costs Incurred			
26						
27	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,239	1.68%	72,319
28			Studies, and/or Actual Costs Incurred			
29						
30	**TOTAL**			$479,011	1.28%	$36,914,788

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

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		$737		$585
3		Other Reimbursable Exp		7		2
4		Network Circuit Charges		3,478		900
5		Contract Services		2,949		0
6		Office Services		3		1
7						
8		Capital	Actual Costs Incurred			
9		Contract Services		23,465		22,956
10		Materials		8,706		8,176
11		Office Services		2,515		690
12		Other Reimbursable Exp		7		2
13						
14						
15		Total Knife River Corporation Operating Revenues for the Year 2008			$1,640,683,000	
16		Excludes Intersegment Eliminations				
17						
18						
19						
20						
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$41,867	0.0026%	$33,312

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

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**	Natural Gas	Actual Costs Incurred			
2		Purchases/Transportation		$37,633,274		$12,099,632
3						
4		Expense	Actual Costs Incurred			
5		Contract Services		22,721		1,676
6		Office Materials		12,845		3,456
7		Materials		6,643		200
8		Easements		10		
9		Reference Materials		9,430		2,306
10		Public Info Mtgs		3,898		896
11		Seminars & Meeting Registration		3,277		966
12		Meals		218		20
13		Other Reimbursable Exp		53		14
14		Freight		90		0
15						
16		Capital	Actual Costs Incurred			
17		Contract Services		109,925		15,155
18		Materials		34,297		19,297
19						
20						
21		Total WBI Operating Revenues for the Year 2008			$1,244,432,000	
22		Excludes Intersegment Eliminations				
23						
24	**TOTAL**	**Grand Total Affiliate Transactions**		$37,836,681	3.0405%	$12,143,618

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

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**	Expense	Actual Costs Incurred			
2	**SERVICES GROUP, INC**	Materials		$1,251		$1,249
3						
4		Capital	Actual Costs Incurred			
5		Contract Services		134,568		129,608
6		Materials		327		90
7						
8						
9		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2008			$1,257,319,000	
10		Excludes Intersegment Eliminations				
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$136,146	0.0108%	$130,947

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2008

Line	(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	$149,777		$30,881
3		Rent	Actual Costs Incurred	221,772		57,355
4		Cost of Service		79,144		20,469
5						
6		Capital				
7		Corporate Aircraft	Actual Costs Incurred	1,026		302
8		Contract Services		26,819		7,354
9		Materials		585,351		160,500
10						
11						
12		Total Centennial Holdings Capital, LLC Operating Revenues for the Year 2008			$10,501,000	
13		Excludes Intersegment Eliminations				
14						
15						
16						
17						
18						
19						
20						
21						
25	**TOTAL**	**Grand Total Affiliate Transactions**		$1,063,889	10.1313%	$276,861

* 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 - GAS

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		$80		$22
3						
4						
5		Total MDU Energy Capital Operating Revenues for the Year 2008			$626,346,000	
6		Grand Total Affiliate Transactions				
7						
8						
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10						
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21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$80	0.0000%	$22

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**	MDU RESOURCES GROUP, INC.				
2	**CORPORATION**	Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$87,619		
4		Advertising	Costs Incurred	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**	MONTANA-DAKOTA UTILITIES CO.				
2	**CORPORATION**	Communications Department	* Various Corporate Overhead Allocation			
3		Network Circuit Charges	Factors, Cost of Service Factors, Time	2,951		
4			Studies and /or Actual Costs Incurred			
5						
6						
7		Office Services	* General Office Complex and Office			
8		Contract Services	Supplies Cost of Service Allocation	1,758		
9		Express Mail	Factors	12,327		
10		Rental of Office Equipment		363		
11		Office Expenses		106		
12		Postage		7,306		
13		Cost of Service - General Office Buildings		339,760		$75,348
14						
15						
16		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
17		Payroll	Factors and /or Actual Costs Incurred	4		
18						
19						
20		Transportation & Procurement	* Various Corporate Overhead Allocation			
21		Office Expenses	Factors and /or Actual Costs Incurred	1		
22		Utilities		9		
23						
24		Other Direct Charges	Actual Costs Incurred			
25		Employee Discounts		56,524		7,046
26		Permits & Filing Fees		14,367		
27		Electric Consumption		107,634		
28		Gas Consumption		97,686		63,609
29		Miscellaneous		79,079		907
30		Computer/Software Support		1,198,314		
31		Network Circuit Charges		35,450		
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**	Audit Costs		651,937		
2	**CORPORATION**	Telephone Charges		33,025		
3		Employee Reimbursable Exp		46,186		
4		Misc Employee Benefits		25,402		
5		Contract Services		20,878		
6						
7		**Total Montana-Dakota Utilities Co.**		$2,731,067	0.1731%	$146,910
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	0.0307%	
17						
18		**Grand Total Affiliate Transactions**		$16,779,935	1.0635%	$146,910
19						
20		**Total Knife River Corporation Operating Expenses for 2008 - Excludes Intersegment Eliminations**			$1,577,834,000	

* 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	**WBI HOLDINGS, INC.**	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$89,249		
4		Advertising	Studies and/or Actual Costs	53,589		
5		Air Service	Incurred	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			
8		Expense	Office Supplies cost of			
9		Contract Services	Service Allocation Factors	1,749		
10		Rental of Office Equipment		361		
11		Express Mail		12,161		
12		Office Expenses		242		
13		Postage		7,270		
14		Cost of Service - General Office Buildings		305,659		$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 Reimbruseable Expenses		273		
24		OfficeTelephone		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			
2		Office Expenses	Allocation Factors, Time	$3		
3		Office Telephone	Studies and/or Actual Costs	247		
4		Permits & Filing Fees	Incurred	3		
5		Utilities		13		
6		Expense				
7		Office Expenses		3		
8		Utilities		28		
9						
10		Other Direct Charges	Actual Costs Incurred			
11		Utility/Merchandise Discounts		171,762		$103,267
12		Audit Costs		413,135		
13		Contract Maintenance Services		74,230		
14		Radio Maintenance		2,017		
15		Vehicle Maintenance		16,890		
16		Permits & Filing Fees		24,234		
17		Misc Employee Benefits		13,125		
18		Computer/Software Support		315,632		
19		Cathodic Protection		16,039		6,678
20		Purchased Power for Compressor Stations		210,092		194,991
21		Electric Compressor - Electricity Cost		1,077,081		777,327
22		Office Building Utilities		287,227		101,213
23		Legal Fees		16,017		
24		Employee Reimbursable Exp		29,061		
25		Telephone Charges		11,722		
26		Miscellaneous		128,329		9,861
27		BitterCreek Projects		22,380		22,380

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.**					
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	($6,513)		
13		Federal & State Tax Liability Payments		71,640,182		
14		Tax Deferred Savings Plan		9,108		
15		Miscellaneous Reimbursements		(65,996)		
16		**Total Other Transactions/Reimbursements**		$71,576,781	7.2160%	
17						
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**	MDU RESOURCES GROUP, INC.				
2	**SERVICES GROUP INC**	Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$20,645		
4		Advertising	Studies and/or Actual Costs	12,446		
5		Air Service	Incurred	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**	MONTANA-DAKOTA UTILITIES CO.				
2	**SERVICES GROUP INC**	Communications Department	* Various Corporate Overhead			
3		Air Service	Allocation Factors, Cost of	$32		
4		Automobile	Service Factors, Time Studies	33		
5		Contract Services	and/or Actual Costs Incurred	3		
6		Meals & Entertainment		27		
7		Office Expenses		1,238		
8		Office Telephone		33,479		
9		Payroll		10,486		
10		Employee Reimbursable Expense		106		
11		Materials		302		
12		Annual Easements		32		
13		Utilities		2		
14		Industry Dues & Licenses		23		
15		Seminars & Meeting Registrations		75		
16						
17		Office Services	* General Office Complex and			
18		Contract Services	Office Supplies Cost of Service	417		
19		Rental of Office Equip	Allocation	86		
20		Express Mail		2,917		
21		Office Expenses		30		
22		Postage		1,728		
23		Cost of Service - General Office Buildings		125,366		$27,802
24						
25		Transportation Department	* Various Corporate Overhead			
26		Office Supplies	Allocation Factors, Time Studies	1		
27		Utilities	and/or Actual Costs Incurred	14		
28						
29						
30		Prior Year Payroll Correction		(6)		
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**	Other Direct Charges	Actual Costs Incurred			
2	**SERVICES GROUP INC**	Legal Fees		$6,306		
3		Air Service		2,799		
4		Computer/Software Support		24,213		$1,128
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						
16		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
17		Federal & State Tax Liability Payments		$34,295,528		
18		Insurance		18,081		
19		Miscellaneous Reimbursements		(436,651)		($14,217)
20		KESOP Carrying Costs		(116,142)		
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**			$ 1,175,834,000	
28						

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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	**CENTENNIAL ENERGY**	MDU RESOURCES GROUP, INC.				
2	**RESOURCES**	Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time Studies	$4,581		
4		Advertising	and/or Costs Incurred	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			
3		Office Telephone	Allocation Factors, Cost of Service	$149		
4			Factors, Time Studies and/or			
5			Actual Costs Incurred			
6						
7		Office Services	* General Office Complex and Office			
8		Contract Services	Supplies Cost of Service	96		
9		Express Mail	Allocation Factors	714		
10		Postage		399		
11		Rental of Office Equipment		20		
12		Cost of Service - General Office Buildings		11,431		$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**					
2	**RESOURCES**	OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
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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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**	Other Direct Charges	Actual costs incurred			
4		Aircraft Sale				
5		Computer/Software Costs		$315,869		
6		Employee Reimbursable Exp and Fuel		535,256		
7		Telephone		17,515		
8		Electric Consumption		147,481		
9		Gas Consumption		9,717		
10		Office Expenses		795		
11		Miscellaneous		4,209		
12		**Total Montana-Dakota Utilities Co.**		$1,030,842	18.2871%	
13						
14		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
15		Payroll		$616,083		
16		Federal & State Tax Liability Payments		(3,504,046)		
17		**Total Other Transactions/Reimbursements**		($2,887,963)		
18						
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**	MDU RESOURCES GROUP, INC.				
2	**CAPITAL ****	Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$24,398		
4		Advertising	Studies and/or Actual Costs	14,286		
5		Air Service	Incurred	11,497		
6		Automobile		1,935		
7		Bank Services		33,757		
8		Corporate Aircraft		10,916		
9		Consultant Fees		80,706		
10		Contract Services		151,341		
11		Computer Rental		327		
12		Directors Expenses		92,418		
13		Employee Benefits		30,508		
14		Employee Meeting		18,868		
15		Employee Reimbursable Expense		18,920		
16		Express Mail		19		
17		Insurance		161,410		
18		Legal Retainers & Fees		153,007		
19		Meal Allowance		204		
20		Cash Donations		5,262		
21		Meals & Entertainment		7,982		
22		Moving Expense		1,329		
23		Industry Dues & Licenses		11,652		
24		Office Expenses		8,945		
25		Supplemental Insurance		725,466		
26		Permits & Filing Fees		2,261		
27		Postage		1,733		
28		Payroll		1,673,440		
29		Reference Materials		14,771		
30		Rental		330		
31		Seminars & Meeting Registrations		9,884		
32		Software Maintenance		18,859		
33		Telephone		9,664		
34		Training Material		5,568		
35		**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**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL ****	Communications Department	* Various Corporate Overhead			
3		Office Telephone	Allocation Factors, Cost of	$607		
4			Service Factors, Time Studies			
5			and/or Actual Costs Incurred			
6						
7		Office Services	* General Office Complex and			
8		Contract Services	Office Supplies Cost of Service	388		
9		Rental of Office Equip	Allocation	80		
10		Express Mail		2,567		
11		Postage		1,620		
12		Cost of Service - General Office Buildings		84,489		$18,737
13						
14		Finance	* Various Corporate Overhead			
15		Air Services	Allocation Factors, Cost of Service	75		
16		Corporate Aircraft	Factors, Time Studies and/or	586		
17		Payroll	Actual Costs Incurred	98,524		
18		Employee Reimbursable Expense		38		
19		Meals & Entertainment		60		
20		Reference Materials		15		
21						
22		Accounting	* Various Corporate Overhead			
23		Payroll	Allocation Factors, Cost of Service	17,916		
24		Employee Reimbursable Expense	Factors, Time Studies and/or	51		
25		Meals & Entertainment	Actual Costs Incurred	82		
26		Reference Materials		33		
27						
28		President & CEO	* Various Corporate Overhead			
29		Payroll	Allocation Factors, Cost of Service	319,535		
30		Employee Reimbursable Expense	Factors, Time Studies and/or	1,670		
31		Meals & Entertainment	Actual Costs Incurred	216		
32		Reference Materials		336		

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**				

* 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	Actual costs incurred			
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	$69,617,491	$93,910,680	34.90%
2					
3		Operating Expenses			
4	401	Operation Expenses	$61,502,078	$85,519,863	39.05%
5	402	Maintenance Expense	884,997	1,033,997	16.84%
6	403	Depreciation Expense	2,398,077	2,588,492	7.94%
7	404-405	Amort. & Depl. of Gas Plant	179,882	193,016	7.30%
8	406	Amort. of Gas Plant Acquisition Adjustments			
9	407.1	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs			
11	407.2	Amort. of Conversion Expense			
12	408.1	Taxes Other Than Income Taxes	2,433,268	3,034,380	24.70%
13	409.1	Income Taxes - Federal	1,043,780	(2,769,498)	-365.33%
14		- Other	186,286	(654,590)	-451.39%
15	410.1	Provision for Deferred Income Taxes	(950,719)	2,836,323	398.33%
16	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(196,923)	490,834	349.25%
17	411.4	Investment Tax Credit Adjustments			
18	411.6	(Less) Gains from Disposition of Utility Plant			
19	411.7	Losses from Disposition of Utility Plant			
20		**TOTAL Utility Operating Expenses**	$67,480,726	$92,272,817	36.74%
21		**NET UTILITY OPERATING INCOME**	$2,136,765	$1,637,863	-23.35%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Gas			
2	480	Residential	$42,915,114	$56,330,800	31.26%
3	481	Commercial & Industrial - Small	24,450,646	33,413,793	36.66%
4		Commercial & Industrial - Large	16,402	25,411	54.93%
5	482	Other Sales to Public Authorities			
6	484	Interdepartmental Sales			
7	485	Intracompany Transfers			
8		Net Unbilled Revenue	678,237	2,593,461	282.38%
9		**TOTAL Sales to Ultimate Consumers**	68,060,399	92,363,465	35.71%
10	483	Sales for Resale			
11		**TOTAL Sales of Gas**	$68,060,399	$92,363,465	35.71%
12		Other Operating Revenues			
13	487	Forfeited Discounts & Late Payment Revenues			
14	488	Miscellaneous Service Revenues	$73,788	$58,365	-20.90%
15	489	Revenues from Transp. of Gas for Others 1/	1,309,619	1,200,720	-8.32%
16	490	Sales of Products Extracted from Natural Gas			
17	491	Revenues from Nat. Gas Processed by Others			
18	492	Incidental Gasoline & Oil Sales			
19	493	Rent From Gas Property	117,649	92,242	-21.60%
20	494	Interdepartmental Rents			
21	495	Other Gas Revenues	56,036	195,888	249.58%
22		**TOTAL Other Operating Revenues**	1,557,092	1,547,215	-0.63%
23		**Total Gas Operating Revenues**	$69,617,491	$93,910,680	34.90%
24					
25	496	(Less) Provision for Rate Refunds			
26					
27		**TOTAL Oper. Revs. Net of Pro. for Refunds**	$69,617,491	$93,910,680	34.90%

1/ Includes unbilled revenue.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

	Account Number & Title	Last Year	This Year	% Change
1	**Production Expenses**			
2	Production & Gathering - Operation			
3	750 Operation Supervision & Engineering			
4	751 Production Maps & Records			
5	752 Gas Wells Expenses			
6	753 Field Lines Expenses			
7	754 Field Compressor Station Expenses		NOT	
8	755 Field Compressor Station Fuel & Power		APPLICABLE	
9	756 Field Measuring & Regulating Station Expense			
10	757 Purification Expenses			
11	758 Gas Well Royalties			
12	759 Other Expenses			
13	760 Rents			
14	**Total Operation - Natural Gas Production**			
15	Production & Gathering - Maintenance			
16	761 Maintenance Supervision & Engineering			
17	762 Maintenance of Structures & Improvements			
18	763 Maintenance of Producing Gas Wells			
19	764 Maintenance of Field Lines			
20	765 Maintenance of Field Compressor Sta. Equip.		NOT	
21	766 Maintenance of Field Meas. & Reg. Sta. Equip.		APPLICABLE	
22	767 Maintenance of Purification Equipment			
23	768 Maintenance of Drilling & Cleaning Equip.			
24	769 Maintenance of Other Equipment			
25	**Total Maintenance- Natural Gas Prod.**			
26	**TOTAL Natural Gas Production & Gathering**			
27	Products Extraction - Operation			
28	770 Operation Supervision & Engineering			
29	771 Operation Labor			
30	772 Gas Shrinkage			
31	773 Fuel			
32	774 Power			
33	775 Materials			
34	776 Operation Supplies & Expenses		NOT	
35	777 Gas Processed by Others		APPLICABLE	
36	778 Royalties on Products Extracted			
37	779 Marketing Expenses			
38	780 Products Purchased for Resale			
39	781 Variation in Products Inventory			
40	782 (Less) Extracted Products Used by Utility - Cr.			
41	783 Rents			
42	**Total Operation - Products Extraction**			
43	Products Extraction - Maintenance			
44	784 Maintenance Supervision & Engineering			
45	785 Maintenance of Structures & Improvements			
46	786 Maintenance of Extraction & Refining Equip.			
47	787 Maintenance of Pipe Lines		NOT	
48	788 Maintenance of Extracted Prod. Storage Equip.		APPLICABLE	
49	789 Maintenance of Compressor Equipment			
50	790 Maintenance of Gas Meas. & Reg. Equip.			
51	791 Maintenance of Other Equipment			
52	**Total Maintenance - Products Extraction**			
53	**TOTAL Products Extraction**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

	Account Number & Title	Last Year	This Year	% Change
1	**Production Expenses - continued**			
2				
3	Exploration & Development - Operation			
4	795 Delay Rentals			
5	796 Nonproductive Well Drilling		NOT	
6	797 Abandoned Leases		APPLICABLE	
7	798 Other Exploration			
8	**TOTAL Exploration & Development**			
9				
10	Other Gas Supply Expenses - Operation			
11	800 Natural Gas Wellhead Purchases			
12	800.1 Nat. Gas Wellhead Purch., Intracomp. Trans.			
13	801 Natural Gas Field Line Purchases			
14	802 Natural Gas Gasoline Plant Outlet Purchases			
15	803 Natural Gas Transmission Line Purchases			
16	804 Natural Gas City Gate Purchases	$50,407,723	$77,825,544	54.39%
17	805 Other Gas Purchases			
18	805.1 Purchased Gas Cost Adjustments	(3,603,911)	(6,193,019)	-71.84%
19	805.2 Incremental Gas Cost Adjustments			
20	806 Exchange Gas			
21	807.1 Well Expenses - Purchased Gas			
22	807.2 Operation of Purch. Gas Measuring Stations			
23	807.3 Maintenance of Purch. Gas Measuring Stations			
24	807.4 Purchased Gas Calculations Expenses			
25	807.5 Other Purchased Gas Expenses			
26	808.1 Gas Withdrawn from Storage -Dr.	15,778,320	15,782,707	0.03%
27	808.2 (Less) Gas Delivered to Storage -Cr.	(11,853,434)	(12,981,144)	-9.51%
28	809.2 (Less) Deliveries of Nat. Gas for Processing-Cr.			
29	810 (Less) Gas Used for Compressor Sta. Fuel-Cr.			
30	811 (Less) Gas Used for Products Extraction-Cr.			
31	812 (Less) Gas Used for Other Utility Operations-Cr.			
32	813 Other Gas Supply Expenses	76,794	79,239	3.18%
33	**TOTAL Other Gas Supply Expenses**	$50,805,492	$74,513,327	46.66%
34				
35	**TOTAL PRODUCTION EXPENSES**	$50,805,492	$74,513,327	46.66%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

	Account Number & Title		Last Year	This Year	% Change
1	**Storage, Terminaling & Processing Expenses**				
2					
3	Underground Storage Expenses - Operation				
4	814	Operation Supervision & Engineering			
5	815	Maps & Records			
6	816	Wells Expenses			
7	817	Lines Expenses			
8	818	Compressor Station Expenses			
9	819	Compressor Station Fuel & Power		NOT	
10	820	Measuring & Reg. Station Expenses		APPLICABLE	
11	821	Purification Expenses			
12	822	Exploration & Development			
13	823	Gas Losses			
14	824	Other Expenses			
15	825	Storage Well Royalties			
16	826	Rents			
17		**Total Operation - Underground Strg. Exp.**			
18					
19	Underground Storage Expenses - Maintenance				
20	830	Maintenance Supervision & Engineering			
21	831	Maintenance of Structures & Improvements			
22	832	Maintenance of Reservoirs & Wells			
23	833	Maintenance of Lines			
24	834	Maintenance of Compressor Station Equip.		NOT	
25	835	Maintenance of Meas. & Reg. Sta. Equip.		APPLICABLE	
26	836	Maintenance of Purification Equipment			
27	837	Maintenance of Other Equipment			
28		**Total Maintenance - Underground Storage**			
29		**TOTAL Underground Storage Expenses**			
30					
31	Other Storage Expenses - Operation				
32	840	Operation Supervision & Engineering			
33	841	Operation Labor and Expenses			
34	842	Rents		NOT	
35	842.1	Fuel		APPLICABLE	
36	842.2	Power			
37	842.3	Gas Losses			
38		**Total Operation - Other Storage Expenses**			
39					
40	Other Storage Expenses - Maintenance				
41	843.1	Maintenance Supervision & Engineering			
42	843.2	Maintenance of Structures & Improvements			
43	843.3	Maintenance of Gas Holders			
44	843.4	Maintenance of Purification Equipment		NOT	
45	843.6	Maintenance of Vaporizing Equipment		APPLICABLE	
46	843.7	Maintenance of Compressor Equipment			
47	843.8	Maintenance of Measuring & Reg. Equipment			
48	843.9	Maintenance of Other Equipment			
49		**Total Maintenance - Other Storage Exp.**			
50		**TOTAL - Other Storage Expenses**			
51					
52	**TOTAL - STORAGE, TERMINALING & PROC.**				

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

	Account Number & Title		Last Year	This Year	% Change
1	**Transmission Expenses**				
2	Operation				
3	850	Operation Supervision & Engineering			
4	851	System Control & Load Dispatching			
5	852	Communications System Expenses			
6	853	Compressor Station Labor & Expenses			
7	854	Gas for Compressor Station Fuel		NOT	
8	855	Other Fuel & Power for Compressor Stations		APPLICABLE	
9	856	Mains Expenses			
10	857	Measuring & Regulating Station Expenses			
11	858	Transmission & Compression of Gas by Others			
12	859	Other Expenses			
13	860	Rents			
14	**Total Operation - Transmission**				
15	Maintenance				
16	861	Maintenance Supervision & Engineering			
17	862	Maintenance of Structures & Improvements			
18	863	Maintenance of Mains			
19	864	Maintenance of Compressor Station Equip.		NOT	
20	865	Maintenance of Measuring & Reg. Sta. Equip.		APPLICABLE	
21	866	Maintenance of Communication Equipment			
22	867	Maintenance of Other Equipment			
23	**Total Maintenance - Transmission**				
24	**TOTAL Transmission Expenses**				
25	**Distribution Expenses**				
26	Operation				
27	870	Operation Supervision & Engineering	$534,905	$548,565	2.55%
28	871	Distribution Load Dispatching	60,758	63,883	5.14%
29	872	Compressor Station Labor and Expenses			
30	873	Compressor Station Fuel and Power			
31	874	Mains and Services Expenses	1,059,280	1,099,603	3.81%
32	875	Measuring & Reg. Station Exp.-General	25,599	37,331	45.83%
33	876	Measuring & Reg. Station Exp.-Industrial	11,408	10,506	-7.91%
34	877	Meas. & Reg. Station Exp.-City Gate Ck. Sta.	0	0	0.00%
35	878	Meter & House Regulator Expenses	283,849	289,540	2.00%
36	879	Customer Installations Expenses	746,562	836,606	12.06%
37	880	Other Expenses	925,890	957,235	3.39%
38	881	Rents	53,692	39,347	-26.72%
39	**Total Operation - Distribution**		$3,701,943	$3,882,616	4.88%
40	Maintenance				
41	885	Maintenance Supervision & Engineering	$166,558	$165,647	-0.55%
42	886	Maintenance of Structures & Improvements	712	741	4.07%
43	887	Maintenance of Mains	100,744	104,600	3.83%
44	888	Maint. of Compressor Station Equipment			
45	889	Maint. of Meas. & Reg. Station Exp.-General	28,991	21,578	-25.57%
46	890	Maint. of Meas. & Reg. Sta. Exp.-Industrial	13,188	17,357	31.61%
47	891	Maint. of Meas. & Reg. Sta. Equip.-City Gate			
48	892	Maintenance of Services	113,980	183,513	61.00%
49	893	Maintenance of Meters & House Regulators	182,990	295,566	61.52%
50	894	Maintenance of Other Equipment	104,886	90,278	-13.93%
51	**Total Maintenance - Distribution**		$712,049	$879,280	23.49%
52	**TOTAL Distribution Expenses**		$4,413,992	$4,761,896	7.88%

MONTANA OPERATION & MAINTENANCE EXPENSES Year: 2008

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Customer Accounts Expenses**			
3	Operation				
4	901	Supervision	$171,592	$187,513	9.28%
5	902	Meter Reading Expenses	641,359	454,619	-29.12%
6	903	Customer Records & Collection Expenses	1,204,033	1,212,362	0.69%
7	904	Uncollectible Accounts Expenses	117,648	338,064	187.35%
8	905	Miscellaneous Customer Accounts Expenses	137,923	129,481	-6.12%
9					
10		**TOTAL Customer Accounts Expenses**	$2,272,555	$2,322,039	2.18%
11					
12		**Customer Service & Informational Expenses**			
13	Operation				
14	907	Supervision	$4,520	$36,551	708.65%
15	908	Customer Assistance Expenses	10,044	13,500	34.41%
16	909	Informational & Instructional Advertising Exp.	47,465	50,339	6.05%
17	910	Miscellaneous Customer Service & Info. Exp.	237	85	-64.14%
18					
19		**TOTAL Customer Service & Info. Expenses**	$62,266	$100,475	61.36%
20					
21		**Sales Expenses**			
22	Operation				
23	911	Supervision	$65,734	$56,954	-13.36%
24	912	Demonstrating & Selling Expenses	134,943	141,586	4.92%
25	913	Advertising Expenses	13,913	16,385	17.77%
26	916	Miscellaneous Sales Expenses	18,507	20,653	11.60%
27					
28		**TOTAL Sales Expenses**	$233,097	$235,578	1.06%
29					
30		**Administrative & General Expenses**			
31	Operation				
32	920	Administrative & General Salaries	$1,266,098	$1,079,791	-14.72%
33	921	Office Supplies & Expenses	506,502	569,446	12.43%
34	922	(Less) Administrative Expenses Transferred - Cr.			
35	923	Outside Services Employed	128,361	105,561	-17.76%
36	924	Property Insurance	86,558	62,738	-27.52%
37	925	Injuries & Damages	604,570	431,892	-28.56%
38	926	Employee Pensions & Benefits	1,596,587	2,034,834	27.45%
39	927	Franchise Requirements			
40	928	Regulatory Commission Expenses	10,252	25,690	150.59%
41	929	(Less) Duplicate Charges - Cr.			
42	930.1	General Advertising Expenses	54,296	48,825	-10.08%
43	930.2	Miscellaneous General Expenses	85,540	44,638	-47.82%
44	931	Rents	87,961	62,413	-29.04%
45					
46		**TOTAL Operation - Admin. & General**	$4,426,725	$4,465,828	0.88%
47	Maintenance				
48	935	Maintenance of General Plant	$172,948	$154,717	-10.54%
49					
50		**TOTAL Administrative & General Expenses**	$4,599,673	$4,620,545	0.45%
51	**TOTAL OPERATION & MAINTENANCE EXP.**		$62,387,075	$86,553,860	38.74%

MONTANA TAXES OTHER THAN INCOME

Year: 2008

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$455,751	$453,557	-0.48%
2	Secretary of State	327	227	-30.58%
3	Highway Use Tax	155	210	35.48%
4	Montana Consumer Counsel	52,379	114,964	119.48%
5	Montana PSC	163,343	270,916	65.86%
6	Delaware Franchise Taxes	18,849	18,263	-3.11%
7	Property Taxes	1,737,728	2,170,886	24.93%
8	Tribal Taxes	4,736	5,357	13.11%
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50	**TOTAL MT Taxes other than Income**	$2,433,268	$3,034,380	24.70%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2008

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Able Field Services	Plant update & repair	$91,396	$0	0.00%
2					
3	Aerial Contractors Inc.	Contractor services	1,061,920	0	0.00%
4					
5	Agri Industries Inc.	Contractor services	314,052	19,130	6.09%
6					
7	Ahern Fire Protection	Fire system installation	319,035	0	0.00%
8					
9	All Building Corp	Construction services	677,196	0	0.00%
10					
11	Aptech	Engineering services - L&C Merc Control	118,563	0	0.00%
12					
13	Atlantic Insulco Environmental Services	Environmental work	159,290	0	0.00%
14					
15	Basin Electric Power Coop	Contract Services	171,325	0	0.00%
16					
17	Benco Equipment Co	Vehicle Maintenance	232,299	1,309	0.56%
18					
19	Berger Electric Inc	Boring & pipe installation	82,871	0	0.00%
20					
21	Big K Industries Inc	Contractor services	81,277	0	0.00%
22					
23	Black & Veatch	Contractor services	174,788	0	0.00%
24					
25	Blue Heron Consulting	Consulting services	2,887,728	344,432	11.93%
26					
27	Broadridge	Contractor services	146,584	1,327	0.91%
28					
29	Bullinger Tree Service	Tree trimming service	261,257	0	0.00%
30					
31	Central Trenching Inc	Boring & trenching services	215,247	0	0.00%
32					
33	Chief Construction	Contractor services	482,856	0	0.00%
34					
35	Christensen IR	Investor Relations	87,452	910	1.04%
36					
37	Conduit Constructors, LLC	Contractor services	353,561	0	0.00%
38					
39	Connecting Point	Computer services & software Mainten.	108,509	6,922	6.38%
40					
41	Corridor Exxon Tire & Auto	Vehicle Maintenance	80,120	2,585	3.23%
42					
43	Deloite & Touche	Auditing and consulting services	524,183	30,561	5.83%
44					
45	Dewey & LeBoeuf	Legal Services	1,077,241	11,676	1.08%
46					
47	Energy & Environmental	Contract Services - Environmental	125,412	12	0.01%
48					
49	Environmental Energy Services, Inc	Mercury testing	108,522	0	0.00%
50					

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 12**

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2008

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Environmental Services, LTD	Heskett - Unit 2 maintenance	235,662	0	0.00%
2					
3	Excavating Specialists	Boring & trenching	83,347	34,917	41.89%
4					
5	Fischer Contracting	Contract services	356,291	0	0.00%
6					
7	Forrester, Gary	Lobbying & Promotion	93,991	1,011	1.08%
8					
9	Franz Construction Inc	Construction Services	233,769	0	0.00%
10					
11	G E Energy Services	Construction Services	104,330	0	0.00%
12					
13	Gabe's Construction Co, Inc	Contractor Services	125,919	0	0.00%
14					
15	Great Southwestern Construction, Inc.	Tap installation - Tatanka wind farm	106,795	0	0.00%
16					
17	Hamilton Spray	Contractor Services - wood pole treatment	197,190	0	0.00%
18					
19	Hardy Construction	Construction Services	887,649	8,380	0.94%
20					
21	HDR Inc	Contractor Services	159,867	0	0.00%
22					
23	HessMorganHouse, LLC	Consulting services	81,900	918	1.12%
24					
25	Hydrochem Industrial Services	Boiler cleaning	90,509	0	0.00%
26					
27	Impact Mechanical	Gas comp. equip install - Glendive unit	125,302	0	0.00%
28					
29	Industrial Contractors, Inc.	Construction Services	1,531,199	0	0.00%
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	14,723	15.69%
36					
37	Itron Inc.	Contract services	2,296,218	571,139	24.87%
38					
39	Jarrett Construction Inc	Storm water imp - Glendive & Miles City	156,884	0	0.00%
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	0	0.00%
44		Turbine facilities			
45	La Salle Photography World Wide	Contract Services - Corporate report	84,089	1,003	1.19%
46					
47	Lindquist & Vennum, PLLP	Contract Services - Const Big Stone II	127,057	0	0.00%
48					
49	Litho of Minnesota, Inc	MDU Resources annual report	115,200	1,043	0.91%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS 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	1,656	1.04%
4					
5	Microsoft	Contract services - software maintenance	995,843	19,999	2.01%
6					
7	Midwest ISO	Prelim studies, wind farm & others	286,000	0	0.00%
8					
9	New York Life	Consulting services	377,999	13,300	3.52%
10					
11	Northern Improvement Co	Contractors services	143,911	0	0.00%
12					
13	NYSE Market Inc	Financial services	173,624	1,526	0.88%
14					
15	Oakland Construction., Inc	Boring and trenching - cable replacement	194,826	0	0.00%
16					
17	Oliver Wyman Corp Risk	Consulting Services	75,000	912	1.22%
18	Consulting, Inc				
19	One Call Locators LTD	Line location services	1,426,402	345,570	24.23%
20					
21	Oracle Corp	Software maintenance	1,035,544	125,725	12.14%
22					
23	Ormat Nevada Inc.	Install energy converter - Glen Ullin	7,052,822	0	0.00%
24					
25	Osmose Utilities Services Inc	Contract services - overhead line maint.	158,462	0	0.00%
26					
27	OTP Big Stone II - Trust Acct	Big Stone II Const	1,382,676	0	0.00%
28					
29	Outdoor Services Inc	Contract Services - meter reading	547,443	53,837	9.83%
30					
31	PA Consulting Services Inc	Consulting services - Big Stone II & WY Gen III	114,895	0	0.00%
32					
33	Pole Maintenance Company	Contract services - pole maintenance	255,888	0	0.00%
34					
35	Power Generation Service Inc	Replace turbine parts - L&C	103,846	0	0.00%
36					
37	Presort Plus Inc	Contract services - mail service	174,054	31,253	17.96%
38					
39	Professional Consultants Inc	Consulting serv - BGB & TGB removal	114,796	0	0.00%
40					
41	Progressive Maintenance Co	Custodial services	131,312	13,811	10.52%
42					
43	PSC Industrial Outsourcing Inc.	Boiler maintenance - Heskett	674,219	0	0.00%
44					
45	PSC Intermountain	Boiler maintenance - Heskett	165,935	0	0.00%
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	1,249	0.80%
50					

Company Name: Montana-Dakota Utilities Co. SCHEDULE 12

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

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	0	0.00%
4					
5	Southern Cross Corp	Contract services - leak detection	229,611	83,992	36.58%
6					
7	Standard & Poor's	Financial services	156,919	2,699	1.72%
8					
9	State-Line Contractors Inc	Construction services	514,398	487,319	94.74%
10					
11	Strategic Solutions, LLC	Consulting services - CIS project	89,967	10,731	11.93%
12					
13	Structure Group	Market Midwest Annual Base Maint.	84,800	0	0.00%
14					
15	Sundog	MDU Resources eSource project	143,081	9,718	6.79%
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	3,792	1.02%
22					
23	Temberline Construction Inc	Construction services	117,263	0	0.00%
24					
25	TLT-Babacock Inc	Centrifugal & IVC rebuild - Heskett	165,334	0	0.00%
26					
27	Treasury Management Services	Banking Services	306,044	53,338	17.43%
28					
29	UC4 Software, Inc.	Software Maintenance	125,504	14,969	11.93%
30					
31	Ulmer Tree Service	Tree trimming service	187,229	0	0.00%
32					
33	Utilities International, Inc.	Consulting services	966,423	73,252	7.58%
34					
35	Van Horn Media	Advertising	222,779	37,569	16.86%
36					
37	Wanzek Construction Inc	Contractor services	2,315,162	0	0.00%
38					
39	Wells Fargo Shareowners Services	Stock transfer agent & ESOP Admin	344,234	3,594	1.04%
40					
41	Wenck	Contractor Services - Billings landfill	110,000	26,896	24.45%
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	$2,468,703	5.88%

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				
14				
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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)

Year: 2008

	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			
19	Service cost			
20	Interest Cost	PROPRIETARY SCHEDULE		
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			
29	Actual return on plan assets			
30	Acquisition	PROPRIETARY SCHEDULE		
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			
37	Unrecognized prior service cost	PROPRIETARY SCHEDULE		
38	Unrecognized transition obligation			
39	Accrued benefit cost			
40	**Components of Net Periodic Benefit Costs**			
41	Service cost			
42	Interest cost			
43	Expected return on plan assets			
44	Amortization of prior service cost	PROPRIETARY SCHEDULE		
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			
50	Amount Funded through 401(h)			
51	Amount Funded through Other ________________			
52	TOTAL	PROPRIETARY SCHEDULE		
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

Year: 2008

	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			
21	Acquisition	NOT APPLICABLE		
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 ______________			
41	TOTAL	NOT APPLICABLE		
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			

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 16

Year: 2008

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	PROPRIETARY SCHEDULE						
6							
7							
8							
9							
10							

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 20a 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........	2008	700,000	—	860,702	—	310,800	898,941	9,476(3)	2,779,919
President and CEO	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............	2008	400,000	—	340,306	—	115,440	498,210	7,176(3)	1,361,132
Executive Vice	2007	350,700	—	268,806	—	350,700	555,248	7,026	1,532,480
President, Treasurer and CFO	2006	318,750	—	161,690	—	318,750	635,356	6,876	1,441,422
John G. Harp.................	2008	400,000	—	301,785	—	720,000(4)	338,774(6)	23,230(7)	1,783,789
President and CEO	2007	341,000	—	277,929	—	341,000	47,334(6)	23,080(7)	1,030,343
of MDU Construction Services Group, Inc.	2006	310,000	—	150,566	—	810,000(5)	324,976(6)	31,323(7)	1,626,865
William E. Schneider ...	2008	447,400	—	400,638	—	—	180,801	8,976(3)	1,037,815
President and CEO	2007	422,000	—	383,191	—	206,780	450,347	7,026	1,469,344
of Knife River Corporation	2006	392,000	—	248,217	20,729	392,000	609,916	6,876	1,669,738
Paul K. Sandness	2008	321,400	—	246,228	—	71,351	170,403	9,426(3)	818,808
General Counsel	2007	—	—	—	—	—	—	—	—
and Secretary	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:

	Accumulated Pension Change			**Above Market Earnings**		
Name	**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

		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)
Name (a)	Grant Date (b)	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	—	—	—	—	—	—	
	2/14/08(2)	—	—	—	3,909	39,091	78,182	—	—	—	1,200,485
Vernon A. Raile	2/14/08(1)	65,000	260,000	520,000	—	—	—	—	—	—	
	2/14/08(2)	—	—	—	1,340	13,402	26,804	—	—	—	411,575
John G. Harp	2/14/08(1)	65,000	260,000	520,000	—	—	—	—	—	—	
	2/14/08(2)	—	—	—	1,340	13,402	26,804	—	—	—	411,575
	2/14/08(3)	—	200,000	—							
William E. Schneider	2/14/08(1)	72,703	290,810	581,620	—	—	—	—	—	—	
	2/14/08(2)	—	—	—	1,499	14,991	29,982	—	—	—	460,374
Paul K. Sandness	2/14/08(4)	40,175	160,700	321,400	—	—	—	—	—	—	
	2/14/08(2)	—	—	—	897	8,974	17,948	—	—	—	275,592

(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:

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

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 (l) 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

	Option Awards					Stock Awards			
Name (a)	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

	Option Awards		Stock Awards	
Name (a)	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	Gas Plant in Service	$261,025,044	$288,109,384	10.38%
4	101.1	Property Under Capital Leases			
5	102	Gas Plant Purchased or Sold			
6	104	Gas Plant Leased to Others	25,772	25,772	0.00%
7	105	Gas Plant Held for Future Use			
8	105.1	Production Properties Held for Future Use			
9	106	Completed Constr. Not Classified - Gas			
10	107	Construction Work in Progress - Gas	9,441,802	4,548,121	-51.83%
11	108	(Less) Accumulated Depreciation	(160,748,664)	(167,643,439)	4.29%
12	111	(Less) Accumulated Amortization & Depletion	(886,959)	(967,784)	9.11%
13	114	Gas Plant Acquisition Adjustments	97,266	97,266	0.00%
14	115	(Less) Accum. Amort. Gas Plant Acq. Adj.	(41,114)	(43,934)	6.86%
15	116	Other Gas Plant Adjustments			
16	117	Gas Stored Underground - Noncurrent	2,757,982	3,166,622	14.82%
17	118	Other Utility Plant	814,331,376	883,115,046	8.45%
18	119	Accum. Depr. and Amort. - Other Utl. Plant	(437,270,775)	(454,745,730)	4.00%
19		**TOTAL Utility Plant**	$488,731,730	$555,661,324	13.69%
20	**Other Property & Investments**				
21	121	Nonutility Property	$3,117,373	$3,707,024	18.91%
22	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(1,013,133)	(1,117,112)	10.26%
23	123	Investments in Associated Companies			
24	123.1	Investments in Subsidiary Companies	2,284,551,173	2,478,164,341	8.47%
25	124	Other Investments	40,972,687	35,032,098	-14.50%
26	125	Sinking Funds			
27		**TOTAL Other Property & Investments**	$2,327,628,100	$2,515,786,351	8.08%
28	**Current & Accrued Assets**				
29	131	Cash	$2,633,013	$181,115	-93.12%
30	132-134	Special Deposits	1,200	1,200	0.00%
31	135	Working Funds	163,690	113,921	-30.40%
32	136	Temporary Cash Investments	422,455	1,938,468	358.86%
33	141	Notes Receivable			
34	142	Customer Accounts Receivable	27,981,262	29,930,415	6.97%
35	143	Other Accounts Receivable	3,357,347	2,394,649	-28.67%
36	144	(Less) Accum. Provision for Uncollectible Accts.	(230,059)	(285,809)	24.23%
37	145	Notes Receivable - Associated Companies		57,000,000	
38	146	Accounts Receivable - Associated Companies	30,629,676	26,427,125	-13.72%
39	151	Fuel Stock	4,055,099	4,099,005	1.08%
40	152	Fuel Stock Expenses Undistributed			
41	153	Residuals and Extracted Products			
42	154	Plant Materials and Operating Supplies	9,128,932	10,225,093	12.01%
43	155	Merchandise	1,470,096	1,742,091	18.50%
44	156	Other Material & Supplies			
45	163	Stores Expense Undistributed			
46	164.1	Gas Stored Underground - Current	18,158,827	8,529,714	-53.03%
47	165	Prepayments	4,425,641	4,865,549	9.94%
48	166	Advances for Gas Explor., Devl. & Production			
49	171	Interest & Dividends Receivable			
50	172	Rents Receivable			
51	173	Accrued Utility Revenues	39,762,227	46,729,484	17.52%
52	174	Miscellaneous Current & Accrued Assets	184,014	2,560	-98.61%
53		**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		-100.00%
11	183.2	Other Prelim. Nat. Gas Survey & Invtg. Chrgs.		2,084	
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			
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%

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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
	(Dollars in thousands, as applicable)		
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
			(In thousands)		
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
		(In thousands)	
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)
		(In thousands)			
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
	(In thousands)	
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
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	171,129	173,823	344,952
Construction services	91,385	4,234	95,619
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and contracting	162,025	11,980	174,005
Other	---	---	---
Total	$425,698	$ 190,037	$ 615,735

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

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
		(In thousands)	
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
	(In thousands)	
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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	Balance at December 31, 2008	Fair Value Measurements at December 31, 2008, Using: Quoted Prices in Active Markets for Identical 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 Carrying Amount	2008 Fair Value	2007 Carrying Amount	2007 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 exisitng 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
	(In thousands)	
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
	(Dollars in thousands)	
Authorized:		
Preferred –		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A –		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference –		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series – 100,000 shares	**$10,000**	$10,000
4.70% Series – 50,000 shares	**5,000**	5,000
Total preferred stocks	**$15,000**	$15,000

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

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

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

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

NOTE 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:

	Options Outstanding				Options Exercisable		
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)	Number Exercisable	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)
$ 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	72,979	2.2	16.46	374	67,546	16.48	345
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	(6,127)	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
		(In thousands)	
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
		(In thousands)	
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
	(In thousands)	
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.

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
	(In thousands)	
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
		(In thousands)	
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 *(In thousands)*	2006
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
	(In thousands)			
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
	(In thousands)	
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:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	**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:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	**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
	(In thousands)	
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
	(In thousands)	
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	**Intangible Plant**				
2					
3	301	Organization			
4	302	Franchises & Consents			
5	303	Miscellaneous Intangible Plant	$2,693,241	$2,855,632	6.03%
6					
7	**TOTAL Intangible Plant**		$2,693,241	$2,855,632	6.03%
8					
9	**Production Plant**				
10					
11	Production & Gathering Plant				
12					
13	325.1	Producing Lands			
14	325.2	Producing Leaseholds			
15	325.3	Gas Rights			
16	325.4	Rights-of-Way			
17	325.5	Other Land & Land Rights			
18	326	Gas Well Structures			
19	327	Field Compressor Station Structures			
20	328	Field Meas. & Reg. Station Structures			
21	329	Other Structures		NOT	
22	330	Producing Gas Wells-Well Construction		APPLICABLE	
23	331	Producing Gas Wells-Well Equipment			
24	332	Field Lines			
25	333	Field Compressor Station Equipment			
26	334	Field Meas. & Reg. Station Equipment			
27	335	Drilling & Cleaning Equipment			
28	336	Purification Equipment			
29	337	Other Equipment			
30	338	Unsuccessful Exploration & Dev. Costs			
31					
32	**Total Production & Gathering Plant**				
33					
34	Products Extraction Plant				
35					
36	340	Land & Land Rights			
37	341	Structures & Improvements			
38	342	Extraction & Refining Equipment			
39	343	Pipe Lines		NOT	
40	344	Extracted Products Storage Equipment		APPLICABLE	
41	345	Compressor Equipment			
42	346	Gas Measuring & Regulating Equipment			
43	347	Other Equipment			
44					
45	**Total Products Extraction Plant**				
46					
47	**TOTAL Production Plant**				

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2008

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Natural Gas Storage and Processing Plant**			
3					
4	Underground Storage Plant				
5					
6	350.1	Land			
7	350.2	Rights-of-Way			
8	351	Structures & Improvements			
9	352	Wells			
10	352.1	Storage Leaseholds & Rights			
11	352.2	Reservoirs		NOT	
12	352.3	Non-Recoverable Natural Gas		APPLICABLE	
13	353	Lines			
14	354	Compressor Station Equipment			
15	355	Measuring & Regulating Equipment			
16	356	Purification Equipment			
17	357	Other Equipment			
18					
19		**Total Underground Storage Plant**			
20					
21	Other Storage Plant				
22					
23	360	Land & Land Rights			
24	361	Structures & Improvements			
25	362	Gas Holders			
26	363	Purification Equipment			
27	363.1	Liquification Equipment		NOT	
28	363.2	Vaporizing Equipment		APPLICABLE	
29	363.3	Compressor Equipment			
30	363.4	Measuring & Regulating Equipment			
31	363.5	Other Equipment			
32					
33		**Total Other Storage Plant**			
34					
35	**TOTAL Natural Gas Storage and Processing Plant**				
36					
37		**Transmission Plant**			
38					
39	365.1	Land & Land Rights			
40	365.2	Rights-of-Way			
41	366	Structures & Improvements			
42	367	Mains		NOT	
43	368	Compressor Station Equipment		APPLICABLE	
44	369	Measuring & Reg. Station Equipment			
45	370	Communication Equipment			
46	371	Other Equipment			
47					
48		**TOTAL Transmission Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2008

	Account Number & Title		Last Year	This Year	% Change
1					
2	**Distribution Plant**				
3					
4	374	Land & Land Rights	$37,059	$37,059	0.00%
5	375	Structures & Improvements	195,164	195,164	0.00%
6	376	Mains	25,926,462	27,058,926	4.37%
7	377	Compressor Station Equipment			
8	378	Meas. & Reg. Station Equipment-General	567,347	567,347	0.00%
9	379	Meas. & Reg. Station Equipment-City Gate	128,221	128,221	0.00%
10	380	Services	16,341,565	17,456,137	6.82%
11	381	Meters	14,888,765	17,434,491	17.10%
12	382	Meter Installations			
13	383	House Regulators	1,689,672	1,752,012	3.69%
14	384	House Regulator Installations			
15	385	Industrial Meas. & Reg. Station Equipment	184,923	184,923	0.00%
16	386	Other Prop. on Customers' Premises 1/	161,799	161,799	0.00%
17	387	Other Equipment	996,950	1,001,722	0.48%
18					
19	**TOTAL Distribution Plant**		$61,117,927	$65,977,801	7.95%
20					
21	**General Plant**				
22					
23	389	Land & Land Rights	$26,165	$26,165	0.00%
24	390	Structures & Improvements	444,324	449,416	1.15%
25	391	Office Furniture & Equipment	417,657	245,535	-41.21%
26	392	Transportation Equipment	2,604,331	2,517,360	-3.34%
27	393	Stores Equipment	43,786	43,785	0.00%
28	394	Tools, Shop & Garage Equipment	685,620	765,269	11.62%
29	395	Laboratory Equipment	17,960	17,700	-1.45%
30	396	Power Operated Equipment	1,812,365	1,744,201	-3.76%
31	397	Communication Equipment	165,385	192,293	16.27%
32	398	Miscellaneous Equipment	15,104	15,117	0.09%
33	399	Other Tangible Property			
34					
35	**TOTAL General Plant**		$6,232,697	$6,016,841	-3.46%
36					
37	**Common Plant**				
38					
39	389	Land & Land Rights	$535,523	$950,022	77.40%
40	390	Structures & Improvements	4,507,041	6,851,933	52.03%
41	391	Office Furniture & Equipment	1,030,579	953,754	-7.45%
42	392	Transportation Equipment	881,334	1,044,507	18.51%
43	393	Stores Equipment	9,865	9,742	-1.25%
44	394	Tools, Shop & Garage Equipment	175,018	174,611	-0.23%
45	396	Power Operated Equipment	462	455	-1.52%
46	397	Communication Equipment	268,322	347,458	29.49%
47	398	Miscellaneous Equipment	102,043	124,063	21.58%
48					
49	**TOTAL Common Plant**		$7,510,187	$10,456,545	39.23%
50					
51	**TOTAL Gas Plant in Service**		$77,554,052	$85,306,819	10.00%

1/ Includes gas plant leased to others.

MONTANA DEPRECIATION SUMMARY

Year: 2008

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1	Production & Gathering				
2	Products Extraction				
3	Underground Storage				
4	Other Storage				
5	Transmission				
6	Distribution	$65,977,801	$37,471,927	$39,154,211	3.18%
7	General	6,074,159	3,626,851	3,539,440	1.81%
8	Common	13,254,859	4,002,452	4,447,623	4.34%
9	**TOTAL**	$85,306,819	$45,101,230	$47,141,274	3.26%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock			
3	152 Fuel Stock Expenses - Undistributed			
4	153 Residuals & Extracted Products			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)			
9	Transmission Plant (Estimated)			
10	Distribution Plant (Estimated)	$426,495	$624,348	46.39%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	163 Stores Expense Undistributed			
15				
16	**TOTAL Materials & Supplies**	$426,495	$624,348	46.39%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	D95.7.90			
2	Order Number	5856b			
3					
4	Common Equity		44.810%	12.000%	5.377%
5	Preferred Stock		1.810%	4.653%	0.084%
6	Long Term Debt		53.390%	10.212%	5.452%
7					
8	**TOTAL**				10.913%
9					
10	Actual at Year End				
11					
12	Common Equity		46.706%	12.000%	5.605%
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%		8.892%

STATEMENT OF CASH FLOWS

Year: 2008

	Description	Last Year	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									
7									
8									
9									
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16									
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21									
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 reacquistion 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										
8										
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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.

COMMON STOCK

Year: 2008

		Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share 2/	Dividends Per Share	Retention Ratio	Market Price High	Market Price 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 2008

		Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service	$77,554,052	$85,306,819	10.00%
3	108	(Less) Accumulated Depreciation	45,101,230	47,141,274	4.52%
4					
5		**NET Plant in Service**	$32,452,822	$38,165,545	17.60%
6					
7		CWIP in Service Pending Reclassification	$494,745	$549,950	11.16%
8					
9		Additions			
10	154, 156	Materials & Supplies	$426,495	$624,348	46.39%
11	165	Prepayments	17,962	18,578	3.43%
12		Prepaid Demand/Commodity Charges	1,050,726	1,247,383	18.72%
13		Gas in Underground Storage	6,219,654	3,133,884	-49.61%
14		Other Regulatory Assets	0	225,561	100.00%
15					
16		**TOTAL Additions**	$7,714,837	$5,249,754	-31.95%
17					
18		Deductions			
19	190	Accumulated Deferred Income Taxes	$3,364,866	$4,982,872	48.09%
20	252	Customer Advances for Construction	543,734	713,923	31.30%
21	255	Accumulated Def. Investment Tax Credits	80,900	49,565	-38.73%
22					
23					
24		**TOTAL Deductions**	$3,989,500	$5,746,360	44.04%
25		**TOTAL Rate Base**	$36,672,904	$38,218,889	4.22%
26					
27		**Net Earnings**	$2,136,765	$1,637,863	-23.35%
28					
29		**Rate of Return on Average Rate Base**	5.87%	4.37%	-25.55%
30					
31		**Rate of Return on Average Equity**	4.88%	2.48%	-49.18%
32					
33		Major Normalizing Adjustments & Commission	1/		
34		Ratemaking adjustments to Utility Operations 2/			
35					
36		Adjustment to Operating Revenues			
38		Normalized Margin	$451,840	$252,974	-44.01%
39		Late Payment Revenue	23,606	35,392	49.93%
40		Gain from Disposition of Utility Plant 3/	43,180	43,180	0.00%
41		Penalty Revenue 4/	709	(44,451)	-6369.53%
42					
43		Adjustment to Operating Expenses			
44		Elimination of Promotional & Institutional Advertising	(41,343)	(39,525)	4.40%
45		Elimination of Supplemental Insurance	(77,976)	(336,836)	-331.97%
46		Elimination of 401K Tax Deduction	223,636	215,158	-3.79%
47					
48		Total Adjustments to Operating Income	$415,018	$448,298	8.02%
49		**Adjusted Rate of Return on Average Rate Base**	7.01%	5.57%	-20.54%
50					
51		**Adjusted Rate of Return on Average Equity**	7.01%	4.95%	-29.39%

1/ Restated 2007 to include penalty revenue and 401K tax deduction adjustments.
2/ Updated amounts, net of taxes.
3/ Amortized over five years.
4/ Adjusted to reflect a three year average.

MONTANA COMPOSITE STATISTICS 2008

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$77,687
5	107	Construction Work in Progress	857
6	114	Plant Acquisition Adjustments	
7	104	Plant Leased to Others	13
8	105	Plant Held for Future Use	
9	154, 156	Materials & Supplies	624
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	47,141
12	252	Contributions in Aid of Construction	714
13			
14		**NET BOOK COSTS**	$31,326
15			
16		Revenues & Expenses (000 Omitted)	
17			
18	400	Operating Revenues	$93,911
19			
20	403 - 407	Depreciation & Amortization Expenses	$2,782
21		Federal & State Income Taxes	(97)
22		Other Taxes	3,034
23		Other Operating Expenses	86,554
24		TOTAL Operating Expenses	$92,273
25			
26		Net Operating Income	$1,638
27			
28		Other Income	1,400
29		Other Deductions	1,670
30			
31		**NET INCOME**	$1,368
32			
33		Customers (Intrastate Only)	
34			
35		Year End Average:	
36		Residential	68,138
37		Firm General	8,265
38		Small Interruptible	46
39		Large Interruptible	5
40			
41		**TOTAL NUMBER OF CUSTOMERS**	76,454
42			
43		Other Statistics (Intrastate Only)	
44			
45		Average Annual Residential Use (Dkt))	85
46		Average Annual Residential Cost per (Dkt) ($) * 1/	$8.45
		* Avg annual cost = [(cost per Dkt x annual use) +	
47		(monthly service charge x 12)]/annual use	
48		Average Residential Monthly Bill	$59.85
49		Gross Plant per Customer	$1,016

1/ Reflects revenue per dk effective December 1, 2008.

MONTANA CUSTOMER INFORMATION

Year: 2008

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	219	130	21		151
2	Billings	89,847	44,146	4,304		48,450
3	Bridger	745	409	63		472
4	Crow Agency	1,552	304	74		378
5	Edgar	Not Available	102	8		110
6	Fromberg	486	278	17		295
7	Hardin	3,384	1,260	198		1,458
8	Joliet	575	352	41		393
9	Laurel	6,255	3,745	275		4,020
10	Park City	870	577	24		601
11	Pryor	628	89	13		102
12	Rockvale	Not Available	63	4		67
13	Silesia	Not Available	32	1		33
14	Warren	Not Available	0	2		2
15	Alzada	Not Available	10	7		17
16	Baker	1,695	795	173		968
17	Carlyle	Not Available	7	1		8
18	Fort Peck	240	131	10		141
19	Fairview	709	364	53		417
20	Forsyth	1,944	870	151		1,021
21	Frazer	452	96	14		110
22	Glasgow	3,253	1,612	315		1,927
23	Glendive	4,729	3,038	411		3,449
24	Hinsdale	Not Available	114	20		134
25	Ismay	26	10	4		14
26	Malta	2,120	987	202		1,189
27	Miles City	8,487	3,877	544		4,421
28	Nashua	325	169	19		188
29	Poplar	911	846	133		979
30	Richey	189	118	25		143
31	Rosebud	Not Available	43	6		49
32	Saco	224	39	6		45
33	Savage	Not Available	148	19		167
34	Sidney	4,774	2,330	411		2,741
35	Terry	611	314	56		370
36	St. Marie	183	182	11		193
37	Wibaux	567	217	50		267
38	Whitewater	Not Available	30	9		39
39	Wolf Point	2,663	1,357	200		1,557
40	MT Oil Fields	Not Available	1	3		4
41	**TOTAL Montana Customers**	138,663	69,192	7,898	0	77,090

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				
11				
12				
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31				
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33				
34				
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36				
37				
38				
39				
40				
41				
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	Projects>$1,000,000			
2	Common-Intangible			
3	Replace Customer Information System	$4,467,936	$1,113,577	1/
4	Electric-Steam Production			
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	Electric-Other Production			
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	Electric-Transmission			
13	Install 120MVA Auto Transformer at Tioga, ND Substation	2,367,636	592,978	1/
14	Electric-Distribution			
15	Construct Distribution Substation in Bismarck, ND	1,214,136	0	
16	Gas-Production			
17	Install Gas Extraction Facility at Landfill in Billings, MT	1,428,000	400,370	1/
18				
19	Other Projects<$1,000,000			
20	Electric			
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	Gas			
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.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2008

	Total Company			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
1	January			
2	February			
3	March			
4	April			
5	May			
6	June	NOT APPLICABLE		
7	July			
8	August			
9	September			
10	October			
11	November			
12	December			
13	**TOTAL**			

	Montana			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
14	January			
15	February			
16	March			
17	April			
18	May			
19	June	NOT APPLICABLE		
20	July			
21	August			
22	September			
23	October			
24	November			
25	December			
26	**TOTAL**			

DISTRIBUTION SYSTEM - TOTAL COMPANY & MONTANA Year: 2008

	Total Company			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	29	306,741	7,042,995
2	February	9	298,451	6,000,664
3	March	6	223,269	4,728,787
4	April	2	134,674	3,483,234
5	May	1	130,343	2,422,570
6	June	11	73,550	1,533,521
7	July	29	48,619	1,330,278
8	August	22	51,125	1,397,067
9	September	23	65,862	1,687,591
10	October	26	159,798	3,253,623
11	November	20	205,611	4,746,404
12	December	20	321,934	7,447,591
13	**TOTAL**			45,074,325

	Montana			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
14	January	28	96,306	2,074,634
15	February	9	86,779	1,670,290
16	March	6	58,719	1,344,827
17	April	20	57,124	1,138,916
18	May	1	44,771	825,810
19	June	12	24,968	471,338
20	July	20	19,765	443,586
21	August	22	20,933	522,257
22	September	7	26,675	628,412
23	October	26	50,369	1,099,889
24	November	20	59,677	1,456,138
25	December	19	98,751	2,178,086
26	**TOTAL**			13,854,183

STORAGE SYSTEM - TOTAL COMPANY & MONTANA

Year: 2008

		Total Company						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
1	January	30	29	2,556	182,438	18,226	2,955,404	
2	February	14	9	2,217	165,992	10,868	2,303,862	
3	March	11	6	10,355	101,358	28,025	1,115,571	
4	April	29	1	35,122	38,278	212,203	446,545	
5	May	31	1	44,383	33,011	714,301	100,466	
6	June	25	30	74,249	1,214	1,818,587	3,538	
7	July	5	20	80,688	2,666	2,062,542	12,038	
8	August	15	15	75,991	1,411	2,191,885	6,393	
9	September	17	16	63,407	3,084	1,609,639	17,936	
10	October	4	26	64,547	29,894	740,821	199,742	
11	November	2	20	43,259	69,412	170,192	925,761	
12	December	1	15	5,680	194,902	27,690	3,259,743	
13	**TOTAL**					9,604,979	11,346,999	

		Montana						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
14	January							
15	February							
16	March							
17	April							
18	May							
19	June	NOT AVAILABLE						
20	July							
21	August							
22	September							
23	October							
24	November							
25	December							
26	**TOTAL**							

SOURCES OF GAS SUPPLY

Year: 2008

	Name of Supplier 1/	Last Year Volumes Dkt	This Year Volumes Dkt	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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21					
22					
23					
24					
25					
26					
27					
28					
29	1/ Supplier information is proprietary and confidential.				
30					
31					
32					
33	**Total Gas Supply Volumes**	31,093,670	34,265,973	$4.447	$6.732

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2008

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings **(Mcf or Dkt)**	Achieved Savings **(Mcf or Dkt)**	Difference
1							
2	MT Conservation & DSM Program	$74,661	$41,180	81.30%	N/A	4,399	N/A
3	(As Detailed on Schedule 36B)						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
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21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**	$74,661	$41,180	81.30%	N/A	4,399	N/A

MONTANA CONSUMPTION AND REVENUES

Year: 2008

		Operating Revenues		DK Sold		Avg. No. of Customers	
	Sales of Gas	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$56,330,800	$42,915,114	5,816,464	5,487,526	68,138	67,294
2	Firm General	32,477,324	24,182,920	3,461,670	3,212,229	8,265	8,151
3	Small Interruptible	936,469	267,726	103,905	55,964	6	3
4	Large Interruptible	25,411	16,402	3,686	2,522	0	0
5							
6							
7							
8							
9							
10							
11	TOTAL	$89,770,004	$67,382,162	9,385,725	8,758,241	76,409	75,448
12							
13							
14		Operating Revenues		BCF Transported		Avg. No. of Customers	
15							
16		Current	Previous	Current	Previous	Current	Previous
17	Transportation of Gas	Year	Year	Year	Year	Year	Year
18							
19	Small Interruptible	$685,064	$816,027	0.8	1.0	40	41
20	Large Interruptible	540,118	487,122	3.9	3.2	5	5
21							
22							
23							
24	TOTAL	$1,225,182	$1,303,149	4.7	4.2	45	46

NATURAL GAS UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2008

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (Mcf or Dkt)	Most recent program evaluation
1	Local Conservation					
2						
3						
4						
5						
6						
7						
8	Market Transformation					
9						
10						
11						
12						
13						
14						
15	Research & Development					
16						
17						
18						
19						
20						
21						
22	Low Income					
23	Discounts	$265,171	$0	$265,171		
24	Bill Assistance	65,000	0	65,000		
25	Furnace Safety/Repair	100,000	0	100,000		
26						
27						
28						
29	Other					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42	Total	$430,171	$0	$430,171		2008
43	Number of customers that received low income rate discounts			(Average)	2,475	
44	Average monthly bill discount amount ($/mo)				$8.93	
45	Average LIEAP-eligible household income				N/A	
46	Number of customers that received weatherization assistance				N/A	
47	Expected average annual bill savings from weatherization				N/A	
48	Number of residential audits performed				N/A	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 36B

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 (Mcf or Dkt)	Most recent program evaluation
1	Local Conservation					
2	High Efficiency Furnace	$52,962	$0	$52,962	3,533	2008
3						
4	Programmable Thermostat	5,423	0	5,423	866	2008
5						
6	Weatherization Kits	16,276	0	16,276	N/A	2008
7						
8						
9	Demand Response					
10						
11						
12						
13						
14						
15						
16	Market Transformation					
17						
18						
19						
20						
21						
22						
23	Research & Development					
24						
25						
26						
27						
28						
29						
30	Low Income					
31						
32						
33						
34						
35						
36	Other					
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Total	$74,661	$0	$74,661	4,399	2008