YEAR 2000

ANNUAL REPORT
OF
Montana-Dakota Utilities Company

GAS UTILITY

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

REVISED JULY 25, 1990

IDENTIFICATION

Year: 2000

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	Martin A. White, Bismarck, ND	-
2	Ronald D. Tipton, Bismarck, ND	-
3	C. Wayne Fox, Bismarck, ND	-
4	Lester H. Loble II, Bismarck, ND	-
5	Bruce T. Imsdahl, Bismarck, ND	-
6	Ronald G. Skarphol, Bismarck, ND	-
7	Douglas C. Kane, Bismarck, ND	-
8	Warren L. Robinson, Bismarck, ND	
9		
10		
11	1/ Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc.,	
12	and has no Board of Directors. The affairs of the company are managed by	
13	a Managing Committee, the members of which are provided herein rather	
14	than the directors of MDU Resources Group, Inc.	
15		
16		

Officers

Year: 2000

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chief Executive Officer	Executive	Ronald D. Tipton
2			
3	President	Executive	C. Wayne Fox 1/
4			
5	Executive Vice President	Marketing and Business	Ronald G. Skarphol
6		Development	
7			
8	Vice President	Energy Supply	Bruce T. Imsdahl
9			
10	Vice President	Operations	David L. Goodin
11			
12	Assistant Vice President	Gas Supply	Donald F. Klempel
13			
14	Controller	Accounting and Information	Craig A. Keller
15		Systems	
16			
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19			
20			
21	1/ C. Wayne Fox assumed the position of President effective 8/17/00. Prior to that time he		
22	served as Vice President - Regulatory Affairs & General Services.		
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Company Name: Montana-Dakota Utilities Co. **SCHEDULE 4**

CORPORATE STRUCTURE

Year: 2000

Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
Montana-Dakota Utilities Co. (A Division of MDU Resources Group, Inc.)	Utility	$22,265	20.19%
Great Plains Natural Gas Co. (A Division of MDU Resources Group, Inc.)	Natural Gas Distribution	209	0.19%
WBI Holdings, Inc.	Pipeline and Energy Services and Natural Gas and Oil Production	49,068	44.50%
Knife River Corporation	Construction Materials and Mining	30,113	27.31%
Utility Services, Inc.	Utility Services	8,607	7.81%
TOTAL		$110,262	100.00%

CORPORATE ALLOCATIONS - GAS

Year: 2000

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$4,138	6.00%	$64,862
Advertising	Customer Service & Information	Directly Assignable	12,577	21.78%	45,164
	Sales	Directly Assignable	7,833	15.01%	44,355
	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	4,529	3.04%	144,536
Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	8,018	3.28%	236,704
Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	900	5.08%	16,802
Bank Services	Customer Accounts	Directly Assignable	20,513	21.37%	75,490
	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	14,115	4.33%	311,956
Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,243	3.46%	34,731
Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	35,521	3.77%	907,622
Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	42,740	5.20%	779,070
Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a Combination of Net Plant Investment and Number of Employees	58,166	4.18%	1,334,036
Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on Number of Employees	4,470	4.91%	86,483

Company Name: Montana-Dakota Utilities Co. SCHEDULE 5

CORPORATE ALLOCATIONS - GAS

Year: 2000

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	5,835	5.36%	102,955
Employee Reimbursable Expenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	9,151	3.56%	248,247
Express Mail	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	4	3.60%	107
Freight	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	15	4.40%	326
Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	44,607	4.39%	970,957
	Gas Operations	Actual Costs Incurred	824	28.37%	2,080
Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	64	4.22%	1,452
Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	5,562	4.52%	117,428
Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	5,742	5.15%	105,687
Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3,059	4.30%	68,104
Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience	197,333	14.75%	1,140,810

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - GAS

Year: 2000

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	414	5.19%	7,568
2			Actual Costs Incurred			
3						
4	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or	1,669	4.34%	36,776
5			Actual Costs Incurred			
6						
7	Payroll	Gas Distribution	Directly Assignable	(1,541)	27.13%	(4,139)
8						
9		Customer Accounts	Directly Assignable	(650)	21.89%	(2,320)
10						
11		Sales	Directly Assignable	(147)	24.42%	(455)
12						
13		Administrative & General	Various Corporate Overhead Allocation Factors, Time	354,795	4.87%	6,929,396
14			Studies, and/or Actual Costs Incurred			
15						
16	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or	491	7.42%	6,125
17			Actual Costs Incurred			
18						
19	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or	4,437	4.27%	99,398
20			Actual Costs Incurred			
21						
22	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time	3,053	4.13%	70,849
23	Registrations		Studies, and/or Actual Costs Incurred			
24						
25	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	832	4.48%	17,750
26			Studies, and/or Actual Costs Incurred			
27						
28	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,152	4.44%	46,299
29			Studies, and/or Actual Costs Incurred			
30						
31	**TOTAL**			$852,464	5.72%	$14,047,211

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2000

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		Air Service		$58		$17
3		Consulting Services		21,267		6,407
4		Directors Fees and Expenses		2,267		682
5		Employee Meetings		149		45
6		Employee Training		23,470		7,071
7		Materials		891		891
8		Meals and Entertainment		14		4
9		Office Supplies		740		223
10		Reimbursable Expense		10		3
11		Software Maintenance		62		19
12						
13		Capital	Actual Costs Incurred			
14		Contract Service		468		
15		Materials		8,420		
16		Reimbursable Expense		61		
17						
18						
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24						
25						
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27						
28		Total Knife River Corporation Operating Revenues for the Year 2000			$631,395,703	
29						
30						
31						
32	**TOTAL**	**Grand Total Affiliate Transactions**		$57,877	0.0092%	$15,362

Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2000

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		$60,437,320		$18,510,262
3		Refunds/Adjustments		(12,150,517)		(3,858,190)
4						
5						
6						
7						
8						
9		Expense	Actual Costs Incurred			
10		Contract Services		12,237		4,220
11		Meals & Entertainment		37		11
12		Reimbursable Expenses		146		44
13		Easements		10		
14		Employee Training		3,851		683
15		Materials		730		730
16		Legal Fees		2,596		782
17		Postage		3		1
18						
19		Capital				
20		Contract Services		12,486		
21						
22		Other Transactions/Reimbursements				
23		Miscellaneous		72		
24						
25						
26						
27		Total WBI Operating Revenues for the Year 2000			$734,834,388	
28						
29						
30						
31	**TOTAL**	**Grand Total Affiliate Transactions**		$48,318,971	6.5755%	$14,658,543

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2000

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	**UTILITY SERVICES, INC.**	Expense	Actual Costs Incurred			
2						
3		Contract Services		$13,888		$13,888
4		Materials		102		1
5						
6						
7		Capital				
8		Contract Services	Actual Costs Incurred	1,704		
9						
10						
11		Other Transactions/Reimbursements				
12		Miscellaneous	Actual Costs Incurred	35		
13						
14						
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27						
28		Total USI Operating Revenues for the Year 2000			$169,382,312	
29						
30						
31						
32	**TOTAL**	**Grand Total Affiliate Transactions**		$15,729	0.0093%	$13,889

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2000

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Settlement		$2,539,000		
3		Insurance		448,980		
4		Federal & State Tax Liability Payments		12,510,592		
5		KESOP carrying costs		378,572		
6		Tax Deferred Savings Plan		95,281		
7		Interest		(78,055)		
8		Miscellaneous Reimbursements		41,312		
9						
10		**Total Other Transactions/Reimbursements**		15,935,682	2.7735%	
11						
12		**Grand Total Affiliate Transactions**		$22,677,930	3.9469%	$243,788
13						
14						
15						
16		**Total Knife River Corporation Operating Expenses for 2000**			$574,579,744	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2000

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.	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Insurance	Actual Costs Incurred	$195,241		
3		Federal & State Tax Liability Payments		2,794,250		
4		Dividends on Preferred Stock of WBI		198,000		$45,870
5		Tax Deferred Savings Plan		35,823		
6		KESOP carrying costs		499,995		
7		Interest		(53,490)		
8		Miscellaneous Reimbursements		9,568		
9						
10		**Total Other Transactions/Reimbursements**		$3,679,387	0.5753%	$45,870
11						
12		**Grand Total Affiliate Transactions**		$8,526,002	1.3331%	$377,599
13						
14						
15						
16		**Total WBI Holdings Operating Expenses for 2000**			$639,542,280	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2000

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	UTILITY SERVICES, INC.	Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
2		Corporate Aircraft	Factors, Time Studies and/or	1		
3		Employee Benefits	Actual Costs Incurred	138		
4		Employee Reimbursable Expense		114		
5		Payroll		(562)		
6		Training Material		33		
7						
8						
9		Other Direct Charges	Actual Costs Incurred			
10		Legal Fees		242,477		
11		Contract Services		11,790		
12		Air Service		48,083		
13		Meals and Entertainment		5,890		
14		Employee Reimbursable Expense		19,266		
15		Consulting Service		22,739		
16		Miscellaneous		22,745		
17		Vehicle Purchase		39,500		
18		Permits and Filing Fees		45,000		
19						
20						
21						
22						
23						
24						
25		**Total Montana-Dakota Utilities Co.**		$564,537	0.3695%	$25,500

MONTANA UTILITY INCOME STATEMENT

Year: 2000

		Account Number & Title	Last Year	This Year	% Change
1	400	Operating Revenues	$46,304,084	$64,406,017	39.09%
2					
3		Operating Expenses			
4	401	Operation Expenses	$39,398,866	$55,962,430	42.04%
5	402	Maintenance Expense	767,873	699,567	-8.90%
6	403	Depreciation Expense	1,937,007	2,015,775	4.07%
7	404-405	Amort. & Depl. of Gas Plant	78,045	128,628	64.81%
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	2,060,361	2,010,273	-2.43%
13	409.1	Income Taxes - Federal	606,662	1,803,199	197.23%
14		- Other	126,376	370,657	193.30%
15	410.1	Provision for Deferred Income Taxes	(223,148)	(1,092,017)	-389.37%
16	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(68,838)	5,087	107.39%
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**	$44,683,204	$61,903,599	38.54%
21		**NET UTILITY OPERATING INCOME**	$1,620,880	$2,502,418	54.39%

MONTANA REVENUES

SCHEDULE 9

		Account Number & Title	Last Year	This Year	% Change
1		Sales of Gas			
2	480	Residential	$29,785,499	$36,482,551	22.48%
3	481	Commercial & Industrial - Small	17,068,186	21,541,829	26.21%
4		Commercial & Industrial - Large	1,623		
5	482	Other Sales to Public Authorities			
6	484	Interdepartmental Sales			
7	485	Intracompany Transfers			
8		Net Unbilled Revenue	(1,684,295)	5,129,195	404.53%
9		**TOTAL Sales to Ultimate Consumers**	45,171,013	63,153,575	39.81%
10	483	Sales for Resale			
11		**TOTAL Sales of Gas**	$45,171,013	$63,153,575	39.81%
12		Other Operating Revenues			
13	487	Forfeited Discounts & Late Payment Revenues			
14	488	Miscellaneous Service Revenues	$15,518	$13,578	-12.50%
15	489	Revenues from Transp. of Gas for Others 1/	952,201	1,050,794	10.35%
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	130,950	122,158	-6.71%
20	494	Interdepartmental Rents			
21	495	Other Gas Revenues	34,402	65,912	91.59%
22		**TOTAL Other Operating Revenues**	1,133,071	1,252,442	10.54%
23		**Total Gas Operating Revenues**	$46,304,084	$64,406,017	39.09%
24					
25	496	(Less) Provision for Rate Refunds			
26					
27		**TOTAL Oper. Revs. Net of Pro. for Refunds**	$46,304,084	$64,406,017	39.09%

1/ Includes unbilled revenue.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2000

	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: 2000

	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	$31,385,002	$42,265,379	34.67%
17	805	Other Gas Purchases			
18	805.1	Purchased Gas Cost Adjustments	503,507	2,849,770	465.98%
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.	3,890,642	6,579,026	69.10%
27	808.2	(Less) Gas Delivered to Storage -Cr.	(4,374,390)	(3,941,334)	9.90%
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.	(28,837)	292	101.01%
32	813	Other Gas Supply Expenses	130,482	130,233	-0.19%
33		**TOTAL Other Gas Supply Expenses**	$31,506,406	$47,883,366	51.98%
34					
35		**TOTAL PRODUCTION EXPENSES**	$31,506,406	$47,883,366	51.98%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2000

	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: 2000

	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	$371,799	$353,142	-5.02%
28	871	Distribution Load Dispatching	49,803	49,313	-0.98%
29	872	Compressor Station Labor and Expenses			
30	873	Compressor Station Fuel and Power			
31	874	Mains and Services Expenses	622,321	742,112	19.25%
32	875	Measuring & Reg. Station Exp.-General	27,327	28,596	4.64%
33	876	Measuring & Reg. Station Exp.-Industrial	11,890	12,948	8.90%
34	877	Meas. & Reg. Station Exp.-City Gate Ck. Sta.	15		-100.00%
35	878	Meter & House Regulator Expenses	308,674	445,329	44.27%
36	879	Customer Installations Expenses	718,329	748,558	4.21%
37	880	Other Expenses	687,509	716,857	4.27%
38	881	Rents	17,195	18,659	8.51%
39		**Total Operation - Distribution**	$2,814,862	$3,115,514	10.68%
40	Maintenance				
41	885	Maintenance Supervision & Engineering	$152,044	$149,921	-1.40%
42	886	Maintenance of Structures & Improvements	1,539	245	-84.08%
43	887	Maintenance of Mains	143,828	74,335	-48.32%
44	888	Maint. of Compressor Station Equipment			
45	889	Maint. of Meas. & Reg. Station Exp.-General	14,028	21,076	50.24%
46	890	Maint. of Meas. & Reg. Sta. Exp.-Industrial	5,794	6,830	17.88%
47	891	Maint. of Meas. & Reg. Sta. Equip.-City Gate			
48	892	Maintenance of Services	99,492	77,594	-22.01%
49	893	Maintenance of Meters & House Regulators	98,316	103,582	5.36%
50	894	Maintenance of Other Equipment	83,024	93,168	12.22%
51		**Total Maintenance - Distribution**	$598,065	$526,751	-11.92%
52		**TOTAL Distribution Expenses**	$3,412,927	$3,642,265	6.72%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2000

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Customer Accounts Expenses**			
3	Operation			
4	901 Supervision	$129,170	$129,792	0.48%
5	902 Meter Reading Expenses	406,396	413,917	1.85%
6	903 Customer Records & Collection Expenses	1,112,010	1,147,767	3.22%
7	904 Uncollectible Accounts Expenses	194,255	280,535	44.42%
8	905 Miscellaneous Customer Accounts Expenses	164,872	144,627	-12.28%
9				
10	**TOTAL Customer Accounts Expenses**	$2,006,703	$2,116,638	5.48%
11				
12	**Customer Service & Informational Expenses**			
13	Operation			
14	907 Supervision	$3,480	$3,986	14.54%
15	908 Customer Assistance Expenses	22,060	22,050	-0.05%
16	909 Informational & Instructional Advertising Exp.	19,532	22,291	14.13%
17	910 Miscellaneous Customer Service & Info. Exp.	357	365	2.24%
18				
19	**TOTAL Customer Service & Info. Expenses**	$45,429	$48,692	7.18%
20				
21	**Sales Expenses**			
22	Operation			
23	911 Supervision	$106,520	$106,295	-0.21%
24	912 Demonstrating & Selling Expenses	204,334	205,354	0.50%
25	913 Advertising Expenses	41,037	27,180	-33.77%
26	916 Miscellaneous Sales Expenses	23,148	20,884	-9.78%
27				
28	**TOTAL Sales Expenses**	$375,039	$359,713	-4.09%
29				
30	**Administrative & General Expenses**			
31	Operation			
32	920 Administrative & General Salaries	$774,154	$768,532	-0.73%
33	921 Office Supplies & Expenses	366,630	374,713	2.20%
34	922 (Less) Administrative Expenses Transferred - Cr.			
35	923 Outside Services Employed	140,281	131,448	-6.30%
36	924 Property Insurance	20,664	26,004	25.84%
37	925 Injuries & Damages	251,388	239,396	-4.77%
38	926 Employee Pensions & Benefits	979,046	717,506	-26.71%
39	927 Franchise Requirements			
40	928 Regulatory Commission Expenses	634	1,190	87.70%
41	929 (Less) Duplicate Charges - Cr.			
42	930.1 General Advertising Expenses	4,580	20,756	353.19%
43	930.2 Miscellaneous General Expenses	103,843	150,554	44.98%
44	931 Rents	9,207	8,408	-8.68%
45				
46	**TOTAL Operation - Admin. & General**	$2,650,427	$2,438,507	-8.00%
47	Maintenance			
48	935 Maintenance of General Plant	$169,808	$172,816	1.77%
49				
50	**TOTAL Administrative & General Expenses**	$2,820,235	$2,611,323	-7.41%
51	**TOTAL OPERATION & MAINTENANCE EXP.**	$40,166,739	$56,661,997	41.07%

MONTANA TAXES OTHER THAN INCOME

Year: 2000

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$399,586	$423,963	6.10%
2	Secretary of State	4,675	146	-96.88%
3	Montana Consumer Counsel	44,999	49,090	9.09%
4	Montana PSC	119,149	154,423	29.60%
5	Franchise Taxes	16,250	15,494	-4.65%
6	Property Taxes	1,470,036	1,361,457	-7.39%
7	Tribal Taxes	5,666	5,700	0.60%
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50	**TOTAL MT Taxes other than Income**	$2,060,361	$2,010,273	-2.43%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2000

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	ABB Alstrom Power	Construction Services	$252,725	$0	0.00%
2					
3	Acoustic Comm Systems Inc.	Construction Services	79,979	8,178	10.23%
4					
5	Arthur Andersen LLP	Audit Service	163,250	10,097	6.18%
6					
7	Bullinger Tree Service	Tree Trimming Service	174,847	14	0.01%
8					
9	Caldwell Energy	Construction Services	194,680	0	0.00%
10					
11	Chief Construction	Construction Services	262,528	97	0.04%
12					
13	Christensen & Associates	Consultant - Investor Relations	89,652	3,896	4.35%
14					
15	City Air Mechanical, Inc.	Construction Services	184,377	20,036	10.87%
16					
17	Customerlink	Telemarketing Service	83,868	284	0.34%
18					
19	Cynthia J. Skibinski	Consultant - CIS System	154,710	15,691	10.14%
20					
21	Dakota West	Construction Services	84,850	9,087	10.71%
22					
23	Diversified Graphics Inc.	Annual Report	139,063	6,140	4.42%
24					
25	Friendly Advanced	Consultant - CIS System	76,896	9,252	12.03%
26					
27	Gagnon, Inc.	Construction Services	80,084	0	0.00%
28					
29	GE Power Generation Service	Construction Services	1,972,221	0	0.00%
30					
31	GE-Harris	Construction Services	81,461	0	0.00%
32					
33	Hamilton Spray	Contract Services - Pole Treatment	213,015	0	0.00%
34					
35	Hamlin Electric Company	Construction Services	79,136	0	0.00%
36					
37	Hedahl's of Bismarck	Contract Services - Auto and Work Equip.	141,884	2,716	1.91%
38					
39	Horsley Specialties	Construction Services - Asbestos Removal	154,226	17,098	11.09%
40					
41	Industrial Contractors, Inc.	Construction Services	222,554	0	0.00%
42					
43	J.D. Edwards	Contract Services - Software Maintenance	149,530	16,172	10.82%
44					
45	Knife River Corporation	Consulting Services	144,167	5,854	4.06%
46					
47	Leboeuf, Lamb, Greene & MacRae LLP	Legal Services	125,480	5,514	4.39%
48					
49	Lignite Energy Council	Organization Dues and Assessments	81,070	0	0.00%
50					
51	Lowe Inc.	Consulting Services	120,000	0	0.00%
52					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2000

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Mappcor	Organization Dues and Assessments	236,259	0	0.00%
2					
3	Merrill Corporation	Financial Services	117,719	5,249	4.46%
4					
5	Merrill Lynch & Co.	Financial Services	75,000	0	0.00%
6					
7	New York Life	K-Plan Administrator	188,701	105	0.06%
8					
9	North Central Consultants, LTD	Consulting Services	104,078	0	0.00%
10					
11	Norwest Bank	Stock Transfer Agent	97,917	4,335	4.43%
12					
13	Oakland & Fisher Construction	Construction Services	556,754	0	0.00%
14					
15	One Call Locators, Inc.	Line Location Service	809,044	221,794	27.41%
16					
17	Osmose Wood	Contract Services - Pole Treatment	219,095	0	0.00%
18					
19	Progressive Maintenance	Progressive Maintenance	120,279	13,494	11.22%
20					
21	Rocky Mountain Line	Construction Services	194,656	0	0.00%
22					
23	Roth Trucking	Construction Services	93,919	0	0.00%
24					
25	Skeels Electric Company	Contract Services - Electrical	154,617	16,244	10.51%
26					
27	Southern Cross Corporation	Contract Services - Leak Detection	166,427	54,746	32.89%
28					
29	State-Line Contractors, Inc.	Construction Services	433,112	382,640	88.35%
30					
31	Sterling Software	Consultant - CIS System	118,256	12,882	10.89%
32					
33	Thelen, Reid, & Priest LLP	Legal Services	1,056,870	25,231	2.39%
34					
35	Thermoretec	Construction Services	162,739	0	0.00%
36					
37	Towers Perrin	Consultant - Compensation and Benefits	313,873	21,885	6.97%
38					
39	TSP Three Inc.	Construction Services	90,615	0	0.00%
40					
41	US Bank	Bank Services	104,890	20,789	19.82%
42					
43	Utilities International	Consultant - Financial	87,119	8,814	10.12%
44					
45	Utility Partners, LC	Consultant - Mobile Service Computer	274,746	32,384	11.79%
46					
47	Wells Fargo	Stock Transfer Agent	164,449	7,198	4.38%
48					
49	**TOTAL Payments for Services**		$11,447,387	$957,916	8.37%

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2000

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$21,845	$6,600	30.21%
2				
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42				
43	**TOTAL Contributions**	$21,845	$6,600	30.21%

Pension Costs

Year: 2000

1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: 1		
4	Annual Contribution by Employer: 0	Is the Plan Over Funded? Yes		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**	(000's)	(000's)	
7	Benefit obligation at beginning of year	$129,390	$134,762	-3.99%
8	Service cost	2,857	2,993	-4.54%
9	Interest Cost	10,034	9,032	11.09%
10	Plan participants' contributions	-	-	0.00%
11	Amendments	5,010	2,072	141.80%
12	Actuarial (Gain) Loss	5,713	(11,105)	151.45%
13	Acquisition	-	-	0.00%
14	Benefits paid	(11,610)	(8,364)	-38.81%
15	Benefit obligation at end of year	$141,394	$129,390	9.28%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$205,580	$186,156	10.43%
18	Actual return on plan assets	875	27,788	-96.85%
19	Acquisition	-	-	0.00%
20	Employer contribution	-	-	0.00%
21	Plan participants' contributions	-	-	0.00%
22	Benefits paid	(11,610)	(8,364)	-38.81%
23	Fair value of plan assets at end of year	$194,845	$205,580	-5.22%
24	**Funded Status**	$53,451	$76,190	-29.85%
25	Unrecognized net actuarial loss	(61,330)	(83,146)	26.24%
26	Unrecognized prior service cost	11,167	6,865	62.67%
27	Unrecognized net transition obligation	(2,719)	(3,571)	23.86%
28	Accrued benefit cost	$569	($3,662)	115.54%
29				
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	7.50	7.75	-3.23%
32	Expected return on plan assets	8.50	8.50	0.00%
33	Rate of compensation increase	5.00	5.00	0.00%
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost	$2,857	$2,993	-4.54%
37	Interest cost	10,034	9,032	11.09%
38	Expected return on plan assets	(14,734)	(12,909)	-14.14%
39	Amortization of prior service cost	709	604	17.38%
40	Recognized net actuarial gain	(2,244)	(754)	-197.61%
41	Transition amount amortization	(852)	(852)	0.00%
42	Net periodic benefit cost	($4,230)	($1,886)	-124.28%
43				
44	**Montana Intrastate Costs:**			
45	Pension Costs	($4,230)	($1,886)	-124.28%
46	Pension Costs Capitalized	(424)	(185)	-129.19%
47	Accumulated Pension Asset (Liability) at Year End	569	(3,662)	115.54%
48	**Number of Company Employees:**			
49	Covered by the Plan	1,988	1,997	-0.45%
50	Not Covered by the Plan	25	16	56.25%
51	Active	1,035	1,047	-1.15%
52	Retired	844	844	0.00%
53	Deferred Vested Terminated	109	106	2.83%

Other Post Employment Benefits (OPEBS)

Year: 2000

	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	7.50	7.75	-3.23%
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	Projected Unit Cost	Projected Unit Cost	
11	Rate of compensation increase	5.00	5.00	0.00%
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**VEBA**			
14	**Describe any Changes to the Benefit Plan:**			
15				
16				
	TOTAL COMPANY			
17	**Change in Benefit Obligation**	(000's)	(000's)	
18	Benefit obligation at beginning of year	$45,753	$49,085	-6.79%
19	Service cost	766	902	-15.08%
20	Interest Cost	3,440	3,300	4.24%
21	Plan participants' contributions	560	518	8.11%
22	Amendments	-	3,194	-100.00%
23	Actuarial (Gain) Loss	599	(8,414)	107.12%
24	Acquisition	-	-	0.00%
25	Benefits paid	(3,356)	(2,832)	-18.50%
26	Benefit obligation at end of year	$47,762	$45,753	4.39%
27	**Change in Plan Assets**			
28	Fair value of plan assets at beginning of year	$36,271	$30,803	17.75%
29	Actual return on plan assets	(806)	4,037	-119.97%
30	Acquisition	-	-	0.00%
31	Employer contribution	3,003	3,745	-19.81%
32	Plan participants' contributions	560	518	8.11%
33	Benefits paid	(3,356)	(2,832)	-18.50%
34	Fair value of plan assets at end of year	$35,672	$36,271	-1.65%
35	**Funded Status**	($12,090)	($9,482)	-27.50%
36	Unrecognized net actuarial loss	(11,809)	(16,255)	27.35%
37	Unrecognized prior service cost	-	-	0.00%
38	Unrecognized transition obligation	22,785	24,623	-7.46%
39	Accrued benefit cost	($1,114)	($1,114)	0.00%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	$766	$902	-15.08%
42	Interest cost	3,440	3,300	4.24%
43	Expected return on plan assets	(2,533)	(2,206)	-14.82%
44	Amortization of prior service cost	-	-	0.00%
45	Recognized net acturial gain	(508)	(90)	-464.44%
46	Transition amount amortization	1,838	1,838	0.00%
47	Net periodic benefit cost	$3,003	$3,744	-19.79%
48	**Accumulated Post Retirement Benefit Obligation**			
49	Amount Funded through VEBA	$3,563	$4,263	-16.42%
50	Amount Funded through 401(h)			
51	Amount Funded through Other ______________			
52	TOTAL	$3,563	$4,263	-16.42%
53	Amount that was tax deductible - VEBA	$2,503 1/	$3,236	-22.65%
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other __________			
56	TOTAL	$2,503	$3,236	-22.65%

1/ Estimated.

Other Post Employment Benefits (OPEBS) Continued

Year: 2000

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	1,772	1,787	-0.84%
3	Not Covered by the Plan	25	16	56.25%
4	Active	986	995	-0.90%
5	Retired	600	590	1.69%
6	Spouses/Dependants covered by the Plan	186	202	-7.92%
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			
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			
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			
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			
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			
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			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other 1/	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Martin A. White - President & C.E.O.	$394,269	$333,239	$596,343	$1,323,851	$760,972	74%
2	Douglas C. Kane - Executive Vice President Chief Administrative & Corporate Development Officer	226,654	140,035	282,853	649,542	408,998	59%
3	Ronald D. Tipton - President & C.E.O. of Montana-Dakota Utilities Co.	254,277	135,024	285,680	674,981	425,230	59%
4	Warren L. Robinson - Executive Vice President, Treasurer & Chief Financial Officer	188,462	110,912	205,879	505,253	355,484	42%
5	Lester H. Loble, II - Vice President, Secretary & General Counsel	161,654	81,486	158,184	401,324	285,088	41%

1/ See page 20a for details.

EXECUTIVE COMPENSATION

Shown below is information concerning the annual and long-term compensation for services in all capacities to the Company for the calendar years ending December 31, 2000, 1999, and 1998, for those persons who (i) served as the Chief Executive Officer during 2000, and (ii) were the other four most highly compensated executive officers of the Company at December 31, 2000 (the "Named Officers"). Footnotes supplement the information contained in the Tables.

TABLE 1: SUMMARY COMPENSATION TABLE[1]

		Annual compensation			Long-term compensation			
					Awards		Payouts	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Name and principal position	Year	Salary ($)	Bonus(2) ($)	Other annual compen-sation(3) ($)	Restricted stock awards ($)	Securities underlying Options/ SARs (#)	LTIP payouts ($)	All other compen-sation(8) ($)
Martin A. White	2000	394,269	333,239		198,125(4)	—	393,118(7)	5,100
—Chairman of the Board,	1999	323,077	203,960		229,063(5)	—	—	4,872
President & C.E.O.	1998	254,808	139,461		54,157(5)	122,760(6)	—	5,484
Douglas C. Kane	2000	226,654	140,035		99,063(4)	—	178,690(7)	5,100
—Executive Vice President,	1999	210,220	79,146		114,532(5)	—	—	5,100
Chief Administrative & Corporate Development Officer	1998	210,185	63,032		62,689(5)	55,800(6)	—	4,800
Ronald D. Tipton	2000	254,277	135,024		99,063(4)	—	181,517(7)	5,100
—C.E.O. of Montana-Dakota	1999	235,508	70,327		114,532(5)	—	—	4,863
Utilities Co. and Great Plains Natural Gas Co.	1998	223,491	103,500		—	49,125(6)	—	4,998
Warren L. Robinson	2000	188,462	110,912		79,250(4)	—	121,529(7)	5,100
—Executive Vice President,	1999	172,396	86,591		91,625(5)	—	—	4,872
Treasurer & Chief Financial Officer	1998	150,865	57,855		43,771(5)	37,950(6)	—	4,526
Lester H. Loble, II	2000	161,654	81,486	4,551	59,438(4)	—	89,345(7)	4,850
—Vice President, General Counsel	1999	150,750	55,355	5,741	68,719(5)	—	—	4,523
& Secretary	1998	139,694	43,848	3,963	41,916(5)	27,900(6)	—	4,191

(1) All share amounts in the table are adjusted to reflect the Company's three-for-two stock split on July 13, 1998.

(2) Granted pursuant to the Executive Incentive Compensation Plan.

(3) Above-market interest on deferred compensation.

(4) Valued at fair market value on the date of grant. The restricted stock will vest nine years from the date of grant, assuming continued employment. Vesting of some or all shares may be accelerated if total shareholder return equals or exceeds the 50th percentile of the proxy peer group over a three year performance cycle. Nonpreferential dividends are paid on the restricted stock.

At December 31, 2000, the Named Officers held the following amounts of restricted stock: Mr. White—22,190 shares ($721,841); Mr. Kane—12,535 shares ($407,764); Mr. Tipton—10,000 shares ($325,300); Mr. Robinson—9,770 shares ($317,818); and Mr. Loble—7,695 shares ($250,318).

(5) Valued at fair market value on the date of grant. Nonpreferential dividends are paid on the restricted stock.

(6) Options granted pursuant to the 1992 KESOP for the 1998-2000 performance cycle.

(7) Dividend equivalents paid with respect to options granted pursuant to the 1992 KESOP for the 1998-2000 performance cycle.

(8) Totals shown are the Company contributions to the Tax Deferred Compensation Savings Plan.

TABLE 2: AGGREGATED OPTION/SAR EXERCISES IN LAST FISCAL YEAR AND FISCAL YEAR-END OPTION/SAR VALUES

(a) Name	(b) Shares acquired on exercise (#)	(c) Value realized ($)	(d) Number of securities underlying unexercised options at fiscal year-end(1) (#) Exercisable	Unexercisable	(e) Value of unexercised, in-the-money options at fiscal year-end ($) Exercisable	Unexercisable
Martin A. White	—	—	—	122,760	—	1,400,078
Douglas C. Kane	46,343	487,939	—	55,800	—	636,399
Ronald D. Tipton	—	—	—	49,125	—	560,271
Warren L. Robinson	—	—	—	37,950	—	432,820
Lester H. Loble, II	—	—	14,850	27,900	299,921	318,199

(1) Vesting is accelerated upon a change in control.

TABLE 3: PENSION PLAN TABLE

Remuneration	Years of Service 15	20	25	30	35
$125,000	$ 79,426	$ 88,022	$ 96,617	$105,213	$113,808
150,000	95,544	105,952	116,360	126,768	137,176
175,000	110,575	122,434	134,292	146,150	158,009
200,000	123,175	135,034	146,892	158,750	170,609
225,000	134,155	146,014	157,872	169,730	181,589
250,000	145,075	156,934	168,792	180,650	192,509
300,000	181,315	193,174	205,032	216,890	228,749
350,000	228,895	240,754	252,612	264,470	276,329
400,000	269,875	281,734	293,592	305,450	317,309
450,000	309,775	321,634	333,492	345,350	357,209
500,000	349,975	361,834	373,692	385,550	397,409

The Table covers the amounts payable under the Salaried Pension Plan and non-qualified Supplemental Income Security Plan (SISP). Pension benefits are determined by the step-rate formula which places emphasis on the highest consecutive 60 months of earnings within the final 10 years of service. Benefits for single participants under the Salaried Pension Plan are paid as straight life amounts and benefits for married participants are paid as actuarially reduced pensions with a survivorship benefit for spouses, unless participants choose otherwise. The Salaried Pension Plan also permits preretirement survivorship benefits upon satisfaction of certain conditions. Additionally, certain reductions are made for employees electing early retirement.

The Internal Revenue Code places maximum limitations on the amount of benefits that may be paid under the Salaried Pension Plan. The Company has adopted a non-qualified SISP for senior management personnel. In 2000, 81 senior management personnel participated in the SISP, including the Named Officers. Both plans cover salary shown in column (c) of the Summary Compensation Table and exclude bonuses and other forms of compensation.

Upon retirement and attainment of age 65, participants in the SISP may elect a retirement benefit or a survivors' benefit with the benefits payable monthly for a period of 15 years.

As of December 31, 2000, the Named Officers were credited with the following years of service under the plans: Mr. White: Pension, 9, SISP, 9; Mr. Kane: Pension, 29, SISP, 19; Mr. Tipton: Pension, 17, SISP, 17; Mr. Robinson: Pension 12, SISP 12; and Mr. Loble: Pension, 13, SISP, 13. The maximum years of service for benefits under the Pension Plan is 35 and under the SISP vesting begins at 3 years and is complete after 10 years. Benefit amounts under both plans are not subject to reduction for offset amounts.

CHANGE-OF-CONTROL ARRANGEMENTS

The Company entered into Change of Control Employment Agreements with the Named Officers in November 1998, which would become effective for a three-year period (with automatic annual extension if the Company does not provide nonrenewal notice at least 60 days prior to the end of each 12-month period) only upon a change of control of the Company. If a change of control occurs, the agreements provide for a three-year employment period from the date they become effective, with base salary not less than the highest amount paid within the preceding twelve months, an annual bonus not less than the highest bonus paid within the preceding three years, and participation in the Company's incentive, savings, retirement and welfare benefit plans.

The agreements also provide that specified payments and benefits would be paid in the event of termination of employment of the Named Officer by the Company, other than for cause or disability, or by the Named Officer for good reason at any time when the agreements are in effect. In such event, each of the Named Officers would receive payment of an amount equal to three times his annual base pay plus three times his highest annual bonus (as defined therein). In addition, under these agreements, each of the officers would receive (i) an immediate pro-rated cash-out of his bonus for the year of termination based on the highest annual bonus and (ii) an amount equal to the excess of (a) the actuarial equivalent of the benefit under Company qualified and nonqualified retirement plans that the executive would receive if he continued employment with the Company for an additional three years over (b) the actual benefit paid or payable under these plans. All benefits of each executive officer under the Company's welfare benefit plans would continue for at least three years. These arrangements also provide for certain gross-up payments to compensate these executive officers for any excise taxes incurred in connection with these benefits and reimbursement for certain outplacement services.

For these purposes, "cause" means the Named Officer's willful and continued failure to substantially perform his duties or willfully engaging in illegal conduct or misconduct materially injurious to the Company, and "good reason" includes the Company's termination of the Named Officer without cause, the assignment to the Named Officer of duties inconsistent with his prior status and position, certain reductions in compensation or benefits, and relocation or increased travel obligations.

A "change of control" is defined as (i) the acquisition by a party or certain related parties of 20% or more of the Company's voting securities; (ii) a turnover in a majority of the Board of Directors without the approval of a majority of the members of the Board as of November 1998; (iii) a merger or similar transaction after which the Company's stockholders hold 60% or less of the voting securities of the surviving entity; or (iv) the stockholders' approval of the liquidation or dissolution of the Company.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

Introduction

The Compensation Committee of the Board of Directors is responsible for determining the compensation of the Company's executive officers. Composed entirely of non-employee Directors, the Committee meets several times each year to review and determine compensation for the executive officers, including the Chief Executive Officer.

Executive Compensation

The Committee firmly believes that appropriate compensation levels succeed in both attracting and motivating high quality employees. To implement this philosophy, the Committee analyzes trends in compensation among comparable companies participating in the oil and gas industry, segments of the energy and mining industries, the peer group of companies used in the graph following this report, and similar companies from general industry. The Committee then sets compensation levels that it believes are competitive within the industry and structured in a manner that rewards successful performance on the job. There are three components of total executive compensation: base salary, annual incentive compensation, and long-term incentive compensation.

In setting base salaries, the Committee does not use a particular formula. In addition to the data referenced above, other factors the Committee uses in its analysis include the executive's current salary in comparison to the competitive industry standard as well as individual performance. Using this system, the Committee granted to Mr. White, the President and Chief Executive Officer, a 20.5% increase in base salary for 2000. This increase took into account Mr. White's personal performance during 2000, his time as chief executive officer, and comparative industry data. During 2000, only approximately 34.6% of Mr. White's compensation was base pay. The remainder was performance-based. This reflects the Committee's belief in the importance of having substantial at risk compensation to provide a direct and strong link between performance and executive pay. The other Named Officers received base salary increases averaging 8.28% for 2000.

In keeping with the Committee's belief that compensation should be directly linked to successful performance, the Company employs both annual and long-term incentive compensation plans. The annual incentive compensation is determined under the Executive Incentive Compensation Plan. The Committee makes awards based upon the level of corporate earnings, cost efficiency, and individual performance. Mr. White received a total of $333,239 (or 150.9% of the targeted amount) in annual incentive compensation for 2000; the other Named Officers received an average of $116,864, or 149.3% of the targeted amount, based upon achievement of corporate earnings and individual performance near the maximum level.

Long-term incentive compensation serves to encourage successful strategic management and is determined through two different vehicles: the 1992 Key Employee Stock Option Plan and the 1997 Executive Long-Term Incentive Plan. Options with a three-year performance cycle (1998-2000) and related dividend equivalents were granted under the 1992 Key Employee Stock Option Plan in 1998. Performance goals established by the Committee and described in the 1999 Proxy Statement for the 1998-2000 performance cycle were exceeded; therefore, exercisability of the options was accelerated and dividend equivalents were earned at 130.0%. No additional options were granted in 2000.

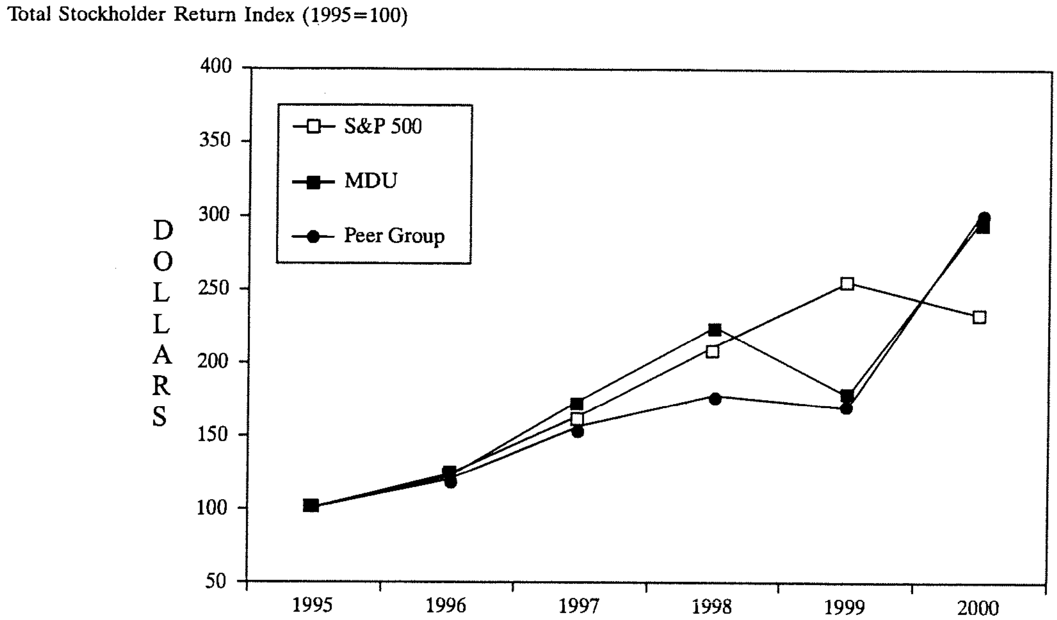
Restricted stock awards were made in 2000 to Mr. White and the other Named Officers under the 1997 Executive Long-Term Incentive Plan. The restricted stock is performance accelerated; it vests automatically within nine years; however, vesting may be accelerated if total shareholder return on MDU Resources stock meets or exceeds the 50th percentile of the peer group (as shown in the performance graph). The number of shares granted was to raise overall compensation levels closer to the median (although still slightly below) level of compensation within the industry. The restricted stock serves to motivate long-term performance and to align the interests of the executives with those of stockholders.

In 1994, the Board of Directors adopted Stock Ownership Guidelines under which executives are required to own Company Common Stock valued from one to four times their annual salary.

The 2000 compensation paid to the Company's executive officers qualified as fully deductible under federal tax laws. The Committee continues to review the impact of federal tax laws on executive compensation, including Section 162(m) of the Internal Revenue Code.

Harry J. Pearce, Chairman   Thomas Everist, Member   Homer A. Scott, Jr., Member

MDU RESOURCES GROUP, INC.
COMPARISON OF FIVE YEAR TOTAL STOCKHOLDER RETURN (1)



	1995	1996	1997	1998	1999	2000
S&P 500	100.00	122.96	163.98	210.85	255.21	231.98
MDU	100.00	121.56	174.59	224.72	177.28	298.00
Peer Group	100.00	118.85	156.35	177.55	168.49	302.28

(1) All data is indexed to December 31, 1995, for the Company, the S&P 500, and the peer group. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group is weighted according to the issuer's stock market capitalization at the beginning of the period. Peer Group issuers are Allete (formerly Minnesota Power, Inc.), Black Hills Corporation, Coastal Corporation, Equitable Resources, Inc., LG&E Energy Corp., The Montana Power Company, NorthWestern Corporation, ONEOK, Inc., Otter Tail Power Company, Questar Corporation, and UGI Corporation. LG&E Energy Corp. merged with Powergen PLC and discontinued trading on December 11, 2000. However, value as of this date was included for total return purposes at December 31, 2000.

BALANCE SHEET

Year: 2000

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Gas Plant in Service	$160,921,671	$191,285,737	18.87%
4	101.1 Property Under Capital Leases			
5	102 Gas Plant Purchased or Sold			
6	104 Gas Plant Leased to Others	29,961	29,961	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	785,019	1,653,150	110.59%
11	108 (Less) Accumulated Depreciation	(96,523,106)	(117,484,590)	21.72%
12	111 (Less) Accumulated Amortization & Depletion	(414,599)	(505,958)	22.04%
13	114 Gas Plant Acquisition Adjustments	97,267	13,942,794	14234.56%
14	115 (Less) Accum. Amort. Gas Plant Acq. Adj.		(171,642)	-100.00%
15	116 Other Gas Plant Adjustments			
16	117 Gas Stored Underground - Noncurrent	4,459,358	1,195,374	-73.19%
17	118 Other Utility Plant	600,593,627	609,335,488	1.46%
18	119 Accum. Depr. and Amort. - Other Utl. Plant	(317,071,289)	(329,835,124)	4.03%
19	**TOTAL Utility Plant**	$352,877,909	$369,445,190	4.69%
20	**Other Property & Investments**			
21	121 Nonutility Property	$161,779	$133,220	-17.65%
22	122 (Less) Accum. Depr. & Amort. of Nonutil. Prop.	(14,883)	(25,123)	68.80%
23	123 Investments in Associated Companies			
24	123.1 Investments in Subsidiary Companies	538,839,875	730,436,178	35.56%
25	124 Other Investments	27,885,507	24,559,856	-11.93%
26	125 Sinking Funds			
27	**TOTAL Other Property & Investments**	$566,872,278	$755,104,131	33.21%
28	**Current & Accrued Assets**			
29	131 Cash	$3,453,935	$7,072,666	104.77%
30	132-134 Special Deposits	1,100	1,200	9.09%
31	135 Working Funds	14,515	16,029	10.43%
32	136 Temporary Cash Investments	5,000,000		-100.00%
33	141 Notes Receivable			
34	142 Customer Accounts Receivable	25,223,733	47,495,868	88.30%
35	143 Other Accounts Receivable	2,610,933	4,258,848	63.12%
36	144 (Less) Accum. Provision for Uncollectible Accts.	(189,276)	(554,752)	193.09%
37	145 Notes Receivable - Associated Companies			
38	146 Accounts Receivable - Associated Companies	9,152,754	11,279,658	23.24%
39	151 Fuel Stock	2,051,748	1,746,988	-14.85%
40	152 Fuel Stock Expenses Undistributed			
41	153 Residuals and Extracted Products			
42	154 Plant Materials and Operating Supplies	5,924,248	6,288,886	6.16%
43	155 Merchandise	722,174	960,692	33.03%
44	156 Other Material & Supplies			
45	163 Stores Expense Undistributed			
46	164.1 Gas Stored Underground - Current	10,010,285	5,895,908	-41.10%
47	165 Prepayments	7,827,961	7,533,214	-3.77%
48	166 Advances for Gas Explor., Devl. & Production			
49	171 Interest & Dividends Receivable	9,938	10,811	8.78%
50	172 Rents Receivable			
51	173 Accrued Utility Revenues	16,040,758	40,145,126	150.27%
52	174 Miscellaneous Current & Accrued Assets	671,844	224,057	-66.65%
53	**TOTAL Current & Accrued Assets**	$88,526,650	$132,375,199	49.53%

BALANCE SHEET

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits (cont.)**			
2					
3	**Deferred Debits**				
4					
5	181	Unamortized Debt Expense	$1,526,835	$1,392,023	-8.83%
6	182.1	Extraordinary Property Losses			
7	182.2	Unrecovered Plant & Regulatory Study Costs			
	182.3	Other Regulatory Assets	5,004,456	3,838,483	-23.30%
	183	Prelim. Electric Survey & Investigation Chrg.	281,397	32,712	-88.38%
8	183.1	Prelim. Nat. Gas Survey & Investigation Chrg.			
9	183.2	Other Prelim. Nat. Gas Survey & Invtg. Chrgs.			
10	184	Clearing Accounts	(45,832)	(167,067)	264.52%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	5,559,763	5,017,758	-9.75%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	9,513,493	8,124,801	-14.60%
16	190	Accumulated Deferred Income Taxes	19,997,919	19,658,579	-1.70%
17	191	Unrecovered Purchased Gas Costs	(2,578,745)	(8,771,627)	240.15%
18	192.1	Unrecovered Incremental Gas Costs			
19	192.2	Unrecovered Incremental Surcharges			
20		**TOTAL Deferred Debits**	$39,259,286	$29,125,662	-25.81%
21					
22	**TOTAL ASSETS & OTHER DEBITS**		$1,047,536,123	$1,286,050,182	22.77%

	Account Number & Title		Last Year	This Year	% Change
23		**Liabilities and Other Credits**			
24					
25	**Proprietary Capital**				
26					
27	201	Common Stock Issued	$57,277,915	$65,267,567*	13.95%
28	202	Common Stock Subscribed			
29	204	Preferred Stock Issued	16,600,000	16,500,000	-0.60%
30	205	Preferred Stock Subscribed			
31	207	Premium on Capital Stock	375,006,302	521,464,938	39.05%
32	211	Miscellaneous Paid-In Capital			
33	213	(Less) Discount on Capital Stock			
34	214	(Less) Capital Stock Expense	(2,694,284)	(2,694,284)	0.00%
35	216	Appropriated Retained Earnings	39,400,577	43,340,068	10.00%
36	216.1	Unappropriated Retained Earnings	204,168,760	257,307,989	26.03%
37	217	(Less) Reacquired Capital Stock			
38		**TOTAL Proprietary Capital**	$689,759,270	$901,186,278	30.65%
39					
40	**Long Term Debt**				
41					
42	221	Bonds	$130,850,000	$130,850,000	0.00%
43	222	(Less) Reacquired Bonds			
44	223	Advances from Associated Companies			
45	224	Other Long Term Debt	43,100,000	43,043,971	-0.13%
46	225	Unamortized Premium on Long Term Debt			
47	226	(Less) Unamort. Discount on Long Term Debt-Dr.	(54,451)	(50,006)	-8.16%
48		**TOTAL Long Term Debt**	$173,895,549	$173,843,965	-0.03%

BALANCE SHEET

	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	$1,257,993	$1,195,672	-4.95%
9	228.3	Accumulated Provision for Pensions & Benefits	15,204,891	16,950,167	11.48%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	31,640		-100.00%
12		**TOTAL Other Noncurrent Liabilities**	$16,494,524	$18,145,839	10.01%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable	$13,000,000	$8,000,000	-38.46%
17	232	Accounts Payable	14,280,166	34,769,716	143.48%
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies	5,143,024	6,047,863	17.59%
20	235	Customer Deposits	1,089,989	1,200,063	10.10%
21	236	Taxes Accrued	9,727,596	16,297,690	67.54%
22	237	Interest Accrued	2,284,323	2,319,289	1.53%
23	238	Dividends Declared	12,170,988	14,422,621	18.50%
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	863,483	2,062,760	138.89%
27	242	Miscellaneous Current & Accrued Liabilities	6,898,665	8,101,718	17.44%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	$65,458,234	$93,221,720	42.41%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	$2,463,919	$2,635,070	6.95%
34	253	Other Deferred Credits	5,988,988	4,373,350	-26.98%
35	254	Other Regulatory Liabilities	15,248,052	1,442,584	-90.54%
36	255	Accumulated Deferred Investment Tax Credits	5,226,005	15,423,176	195.12%
37	256	Deferred Gains from Disposition Of Util. Plant			
38	257	Unamortized Gain on Reacquired Debt			
39	281-283	Accumulated Deferred Income Taxes	73,001,582	75,778,200	3.80%
40		**TOTAL Deferred Credits**	$101,928,546	$99,652,380	-2.23%
41					
42	**TOTAL LIABILITIES & OTHER CREDITS**		$1,047,536,123	$1,286,050,182	22.77%

NOTE 1
SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation
The consolidated financial statements of MDU Resources Group, Inc. and its subsidiaries (company) include the accounts of the following segments: electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, and construction materials and mining. The electric and natural gas distribution segments and a portion of the pipeline and energy services segment are regulated. The company's nonregulated operations include the utility services, natural gas and oil production, and construction materials and mining segments, and a portion of the pipeline and energy services segment. For further descriptions of the company's business segments see Note 9. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generation stations.

The company's regulated businesses are subject to various state and federal agency regulation. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (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 Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Regulation" (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 are generally based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 2 for more information regarding the nature and amounts of these regulatory deferrals.

In accordance with the provisions of SFAS No. 71, intercompany coal sales, which are made at prices approximately the same as those charged to others, and the related utility fuel purchases are not eliminated. All other significant intercompany balances and transactions have been eliminated in consolidation.

Property, plant and equipment
Additions to property, plant and equipment are recorded at cost when first placed in service. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost and cost of removal, less salvage, 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 below, the resulting gains or losses are recognized as a component of income. The company is permitted to capitalize an allowance for funds used during construction (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 $5.2 million, $1.7 million and $1.4 million in 2000, 1999 and 1998, respectively. Property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for natural gas and oil production properties as described below.

Goodwill and other intangible assets
The excess of the cost over the fair value of net assets of purchased businesses is recorded as goodwill and is amortized on a straight-line basis over estimated useful lives. Goodwill was $91.4 million, net of accumulated amortization of $12.0 million as

of December 31, 2000 and was $46.7 million, net of accumulated amortization of $5.1 million as of December 31, 1999. Goodwill amortization expense was $7.0 million, $2.0 million and $1.4 million for 2000, 1999 and 1998, respectively. The weighted average amortization period for goodwill as of December 31, 2000 was 25 years.

Impairment of long-lived assets and intangibles
The company reviews the carrying values of its long-lived assets, including goodwill and identifiable intangibles, 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 an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In 2000, the company experienced significant changes in market conditions at one of its energy marketing operations, which negatively affected the fair value of the assets at that operation. Due to the significance of the decline, the company recorded an impairment charge against goodwill of $3.9 million after tax in the fourth quarter of 2000. The amount related to this impairment is included in "Depreciation, depletion and amortization" in the company's Consolidated Statements of Income. Excluding this impairment and the write-downs of natural gas and oil properties as discussed herein, no other long-lived assets or intangibles have been impaired and accordingly no other impairment losses have been recorded in 2000, 1999 and 1998. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Natural gas and oil
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 revenues of proved reserves and the lower of cost or fair value of unproved properties. Future net revenue is estimated based on end-of-quarter 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.

Due to low natural gas and oil prices, the company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at June 30, 1998 and December 31, 1998. Accordingly, the company was required to write down its natural gas and oil producing properties. These noncash write-downs amounted to $66.0 million ($39.9 million after tax).

Natural gas in underground storage
Natural gas in underground storage for the company's regulated operations is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year is included in inventories and amounted to $11.0 million and $26.1 million at December 31, 2000 and 1999, respectively. The remainder of natural gas in underground storage is included in property, plant and equipment and was $43.6 million and $46.8 million at December 31, 2000 and 1999, respectively.

Inventories
Inventories, other than natural gas in underground storage for the company's regulated operations, consist primarily of materials and supplies of $20.4 million and $15.9 million, aggregates held for resale of $22.7 million and $15.6 million and other

inventories of $9.9 million and $7.0 million as of December 31, 2000 and 1999, respectively. These inventories are stated at the lower of average cost or market.

Revenue recognition
The company recognizes utility revenue each month based on the services provided to all utility customers during the month. For its construction businesses, the company recognizes construction contract revenue on the percentage of completion method. The company recognizes revenue from natural gas and oil production activities only on that portion of production sold and allocable to the company's ownership interest in the related well. The company generally recognizes all other revenues when services are rendered or goods are delivered.

Advertising
The company expenses advertising costs as incurred and the amount of advertising expense for the years 2000, 1999 and 1998, was $2.0 million, $1.3 million and $1.0 million, respectively.

Natural gas costs recoverable 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 which 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 24 months to 28 months from the time such costs are paid.

Income taxes
The company provides deferred federal and state income taxes on all temporary differences. Excess deferred income tax balances associated with the company's rate-regulated activities resulting from the company's adoption of SFAS No. 109, "Accounting for Income Taxes," have been recorded as a regulatory liability and are included in "Other liabilities" in the company's Consolidated Balance Sheets. These regulatory liabilities are expected to be reflected as a reduction in future rates charged 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 which conform to the ratemaking treatment prescribed by the applicable state public service commissions.

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 and restricted stock grants. Common stock outstanding includes issued shares less shares held in treasury.

Comprehensive income
For the years ended December 31, 2000, 1999 and 1998, comprehensive income equaled net income as reported.

Use of estimates
The preparation of financial statements in conformity with generally accepted accounting principles in the United States 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 and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as property depreciable lives, tax provisions, uncollectible

accounts, environmental and other loss contingencies, accumulated provision for revenues subject to refund, costs on long-term construction contracts, unbilled revenues and actuarially determined benefit costs. As better 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, *(In thousands)*	2000	1999	1998
Interest, net of amount capitalized	$41,912	$30,772	$26,394
Income taxes	$30,930	$32,723	$34,498

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

New accounting pronouncements

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), amended by Statement of Financial Accounting Standards No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133" and Statement of Financial Accounting Standards No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities" (all such statements hereinafter referred to as SFAS No. 133). SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special 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.

The company plans to utilize certain derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil. The company intends to designate these contracts as hedges of the underlying purchases or sales and will record derivative assets and liabilities on its balance sheet based on the fair value of the contracts. Such amounts are expected to be substantially offset by an amount that will be recorded in "Accumulated other comprehensive income" on the company's Consolidated Balance Sheets. The fair values of derivative instruments will fluctuate over time due to changes in the underlying commodity prices.

The company adopted SFAS No. 133 on January 1, 2001. SFAS No. 133 will likely impact the company's financial position and could increase volatility in earnings and accumulated other comprehensive income. Based on the contracts outstanding as of January 1, 2001, pretax unrealized gains on derivatives of $2.2 million and pretax unrealized losses on derivatives of $12.3 million would be recognized as assets and liabilities, respectively, on the balance sheet with the offsetting amounts being recorded as a component of accumulated other comprehensive income.

In December 1999, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 101, "Revenue Recognition" (SAB No. 101), which provides guidance on the recognition, presentation and disclosure of revenue in financial statements. The company adopted SAB No. 101 in the fourth quarter of 2000. The adoption of SAB No. 101

did not have a material effect on the company's financial position or results of operations.

NOTE 2

REGULATORY ASSETS AND LIABILITIES

The following table summarizes the individual components of unamortized regulatory assets and liabilities included in the accompanying Consolidated Balance Sheets as of December 31:

(In thousands)	2000	1999
Regulatory assets:		
Long-term debt refinancing costs	$8,125	$9,514
Plant costs	2,668	2,835
Natural gas contract settlement and restructuring costs	1,562	3,000
Postretirement benefit costs	833	1,742
Deferred income taxes	263	7,274
Other	5,490	6,789
Total regulatory assets	18,941	31,154
Regulatory liabilities:		
Taxes refundable to customers	11,656	11,504
Natural gas costs refundable through rate adjustments	8,772	2,579
Plant decommissioning costs	7,601	6,989
Reserves for regulatory matters	6,087	24,231
Deferred income taxes	3,554	6,785
Other	1,193	710
Total regulatory liabilities	38,863	52,798
Net regulatory position	(19,922)	$ (21,644)

As of December 31, 2000, substantially all of the company's regulatory assets, other than certain deferred income taxes, are being reflected in rates charged to customers and are being recovered over the next 1 to 16 years.

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 3

RISK MANAGEMENT ACTIVITIES AND FINANCIAL INSTRUMENTS

Derivatives

The company utilizes derivative financial instruments, including price swap and collar agreements, to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil. 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 financial instruments in the event of nonperformance by counterparties, but does not expect any counterparties to fail to meet their obligations given their existing credit ratings.

The swap and collar agreements call for the company to receive monthly payments from or make payments to counterparties based upon the difference between a fixed and a variable price as specified by the agreements. The variable price is either a quoted natural gas price on the New York Mercantile Exchange (NYMEX), Colorado Interstate Gas Index or other various indexes or an oil price quoted on the NYMEX. The company believes that there is a high degree of correlation because the timing of purchases and production and the swap and collar agreements are closely matched, and hedge prices are established in the areas of operations. For the years ending December 31, 2000, 1999 and 1998, gains or losses on the swap and collar agreements were matched and reported in operating revenues on the Consolidated Statements of Income as a component of the related commodity transaction at the time of settlement with the counterparty.

The following table summarizes hedge agreements entered into by certain wholly owned subsidiaries of the company, as of December 31, 2000. These agreements call for the subsidiaries to receive fixed prices and pay variable prices.
(Notional amount and fair value in thousands)

	Weighted Average Fixed Price (Per MMBtu)	Notional Amount (In MMBtu's)	Fair Value
Natural gas swap agreements maturing in 2001	$ 4.45	5,461	$(12,311)

	Weighted Average Fixed Price (Per barrel)	Notional Amount (In barrels)	Fair Value
Oil swap agreements maturing in 2001	$28.80	593	$ 2,261

The fair value of these derivative financial instruments reflects the estimated amounts that the company would receive or pay to terminate the contracts at the reporting date, thereby taking into account the current favorable or unfavorable position on open contracts. The favorable or unfavorable position is not recorded on the company's Consolidated Balance Sheets as of December 31, 2000 and 1999. Favorable and unfavorable positions related to commodity hedge agreements are expected to be generally offset by corresponding increases and decreases in the value of the underlying commodity transactions.

In the event a derivative financial instrument does not qualify for hedge accounting or when the underlying commodity transaction matures, is sold, is extinguished, or is terminated, the current favorable or unfavorable position on the open contract would be included in results of operations. The company's policy requires approval to terminate a hedge agreement prior to its original maturity. In the event a hedge agreement is terminated, the realized gain or loss at the time of termination would be deferred until the underlying commodity transaction is sold or matures and is expected to generally offset the corresponding increases or decreases in the value of the underlying commodity transaction.

Energy marketing
The company has energy marketing operations that are exposed to risks, including risks relating to changes in natural gas prices and counterparty performance (credit risk), associated with natural gas forward purchase and sale commitments. These commitments involve the purchase and sale of natural gas and related delivery of such commodity. The energy marketing operations seek to match natural gas purchases and sales on specific contracts so that a margin is obtained on the transportation of such commodity as distinguished from earning a margin on changes in market prices. In addition, the energy marketing contracts are generally entered into on a seasonal basis with contracts of a duration generally not exceeding 12 months. Contracts related to these activities are valued at fair value and changes in fair value are recorded as assets or

liabilities on the company's Consolidated Balance Sheets. The net change in fair value representing unrealized gains and losses resulting from changes in market prices on these contracts is reflected in earnings on the company's Consolidated Statements of Income. Net unrealized gains and losses on these contracts were not material in 2000, 1999 or 1998. In general, market risk is the risk of fluctuations in the market price of the commodity being marketed and is influenced primarily by supply and demand. The company monitors and manages its exposure to market risk through a variety of risk management techniques. Such procedures include monitoring commitments and positions, evaluating sensitivity to changes in market prices and market volatility, and reporting to senior management. Credit risk is the risk of loss from nonperformance by counterparties of their contractual obligations. The company maintains credit procedures, which management believes significantly minimize overall credit risk. The company seeks to mitigate credit risk by applying specific eligibility criteria to prospective counterparties and may require letters of credit or similar security to secure payment on such sales contracts. However, despite mitigation efforts, defaults by counterparties may occur. To date, no such defaults have had a material effect on the company's financial position or results of operations.

Fair value of other financial instruments
The estimated fair value of the company's long-term debt and preferred stock subject to mandatory redemption is based on quoted market prices of the same or similar issues. The estimated fair value of the company's long-term debt and preferred stock subject to mandatory redemption at December 31 is as follows:

	2000 Carrying Amount	Fair Value	1999 Carrying Amount	Fair Value
(In thousands)				
Long-term debt	$ 747,761	$772,127	$ 567,873	$ 555,730
Preferred stock subject to mandatory redemption	$ 1,500	$ 927	$ 1,600	$ 1,418

The fair value of other financial instruments for which estimated fair value has not been presented is not materially different than the related carrying amount.

NOTE 4
SHORT-TERM BORROWINGS
The company and its subsidiaries had unsecured short-term lines of credit from a number of banks totaling $75 million at December 31, 2000. These line of credit agreements provide for bank borrowings against the lines and/or support for commercial paper issues. The agreements provide for commitment fees at varying rates. Amounts outstanding on the short-term lines of credit were $8 million at December 31, 2000, and $14.7 million at December 31, 1999. The weighted average interest rate for borrowings outstanding at December 31, 2000 and 1999, was 6.60 percent and 6.97 percent, respectively. The unused portions of the lines of credit are subject to withdrawal based on the occurrence of certain events.

NOTE 5

LONG-TERM DEBT AND INDENTURE PROVISIONS

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

(In thousands)	2000	1999
First mortgage bonds and notes:		
Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, due June 1, 2022	$ 20,850	$ 20,850
Secured Medium-Term Notes, Series A at a weighted average rate of 7.59%, due on dates ranging from October 1, 2004 to April 1, 2012	110,000	110,000
Total first mortgage bonds and notes	130,850	130,850
Senior notes at a weighted average rate of 7.65%, due on dates ranging from January 2, 2001 to October 30, 2018	294,300	151,400
Commercial paper at a weighted average rate of 6.93%, supported by a revolving credit agreement due on September 29, 2003	261,350	223,169
Revolving lines of credit at a weighted average rate of 9.36%, due on dates ranging from November 1, 2001 through December 31, 2002	46,302	45,900
Term credit agreements at a weighted average rate of 7.65%, due on dates ranging from March 15, 2001 through July 1, 2016	12,731	13,970
Pollution control note obligation, 6.20%, due March 1, 2004	2,800	3,100
Other	(572)	(516)
Total long-term debt	747,761	567,873
Less current maturities	19,595	4,328
Net long-term debt	$ 728,166	$ 563,545

Centennial Energy Holdings, Inc., (Centennial) a direct wholly owned subsidiary of the company, has a revolving credit agreement with various banks on behalf of its subsidiaries that supports $315 million of Centennial's $325 million commercial paper program. Under the Centennial commercial paper program, $261.4 million and $223.2 million were outstanding at December 31, 2000 and 1999, respectively. The commercial paper borrowings are classified as long term as Centennial intends to refinance these borrowings on a long-term basis through continued commercial paper borrowings supported by the revolving credit agreement due September 29, 2003. Centennial intends to renew this existing credit agreement on an annual basis.

Centennial has an uncommitted long-term master shelf agreement on behalf of its subsidiaries that allows for borrowings of up to $200 million. Under the master shelf agreement, $150 million was outstanding at December 31, 2000 and none was outstanding at December 31, 1999. The amount outstanding is presented in senior notes in the preceding table.

Under the revolving lines of credit, the company and certain subsidiaries have $48.2 million available as of December 31, 2000. Amounts outstanding under the revolving lines of credit were $46.3 million and $45.9 million at December 31, 2000 and 1999, respectively.

The amounts of scheduled long-term debt maturities for the five years following December 31, 2000 aggregate $19.6 million in 2001; $50.4 million in 2002; $282.7 million in 2003; $21.6 million in 2004 and $69.9 million in 2005.

Substantially all of the company's electric and natural gas distribution properties, with certain exceptions, are subject to the lien of its Indenture of Mortgage. Under the terms and conditions of the Indenture, the company could have issued approximately $295 million of additional first mortgage bonds at December 31, 2000. Certain other debt instruments of the company and its subsidiaries contain restrictive covenants, all of which the company and its subsidiaries are in compliance with at December 31, 2000.

NOTE 6
PREFERRED STOCKS
Preferred stocks at December 31 are as follows:

(Dollars in thousands)	2000	1999
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:		
Subject to mandatory redemption --		
Preferred --		
5.10% Series -- 15,000 shares in 2000 and 16,000 shares in 1999	$ 1,500	$ 1,600
Other preferred stock --		
4.50% Series -- 100,000 shares	10,000	10,000
4.70% Series -- 50,000 shares	5,000	5,000
	15,000	15,000
Total preferred stocks	16,500	16,600
Less sinking fund requirements	100	100
Net preferred stocks	$ 16,400	$ 16,500

The 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 on certain series of preferred stock.

The company is obligated to make annual sinking fund contributions to retire the 5.10% Series preferred stock. The redemption prices and sinking fund requirements, where applicable, are summarized below:

Series	Redemption Price (a)	Sinking Fund Shares	Sinking Fund Price (a)
Preferred stocks:			
4.50%	$105 (b)	---	---
4.70%	$102 (b)	---	---
5.10%	$102	1,000 (c)	$100

(a) Plus accrued dividends.
(b) These series are redeemable at the sole discretion of the company.
(c) Annually on December 1, if tendered.

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

The aggregate annual sinking fund amount applicable to preferred stock subject to mandatory redemption for each of the five years following December 31, 2000, is $100,000.

NOTE 7
COMMON STOCK
At the Annual Meeting of Stockholders held in April 1999, the company's common stockholders approved an amendment to the Certificate of Incorporation increasing the authorized number of common shares from 75 million shares to 150 million shares and reducing the par value of the common stock from $3.33 per share to $1.00 per share.

In May 1998, the company's Board of Directors approved a three-for-two common stock split effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on July 13, 1998, to common stockholders of record on July 3, 1998. Common stock information appearing in the accompanying Consolidated Statements of Income and Notes to Consolidated Financial Statements give retroactive effect to stock split.

The company's Automatic Dividend Reinvestment and Stock Purchase Plan (Stock Purchase Plan) provides participants the opportunity to invest all or a portion of their cash dividends in shares of the company's common stock and to make optional cash payments of up to $5,000 per month for the same purpose. Holders of all classes of the company's capital stock, legal residents in any of the 50 states, and beneficial owners, whose shares are held by brokers or other nominees through participation by their brokers or nominees, are eligible to participate in the Stock Purchase Plan. The company's Tax Deferred Compensation Savings Plan(s) (K-Plan(s)), which were merged effective January 1, 1999, pursuant to Section 401(k) of the Internal Revenue Code are funded with the company's common stock. Since January 1, 1989, the Stock Purchase Plan and K-Plan(s) have been funded primarily by the purchase of shares of common stock on the open market, except for a portion of 1997 where shares of authorized but unissued common stock were used to fund the Stock Purchase Plan and K-Plan(s) and from October 1, 1998 through March 31, 1999, when shares of authorized but unissued common stock were used to fund the Stock Purchase Plan. At December 31, 2000, there were 8.1 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

In November 1998, the company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for one one-thousandth of a share of Series B Preference Stock of the company, without par value, at an exercise price of $125 per one one-thousandth, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of one one-thousandth of a Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.01 per right, at the company's option at any time until any acquiring person has acquired 15 percent or more of the company's common stock.

The company has stock option plans for directors, key employees and employees, which grant options to purchase shares of the company's stock. The company accounts for these option plans in accordance with APB Opinion No. 25 under which no compensation expense has been recognized. The option exercise price is the market value of the stock on the date of grant. Options granted to the 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. Options granted to directors and employees vest at date of grant and three years after date of grant, respectively, and expire ten years after the date of grant. In addition, the company has granted restricted stock awards under a long-term incentive plan, deferred compensation agreement and a restricted stock agreement totaling 348,021 shares, 105,250 shares and 21,135 shares in 2000, 1999 and 1998, respectively. The restricted stock awards granted vest to the participants at various times ranging from three years to nine years from 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 weighted average grant date fair value of the restricted stock grants was $20.81, $22.91 and $23.24 in 2000, 1999 and 1998, respectively. Compensation expense recognized for restricted stock grants was $1.6 million, $722,000 and $123,000 in 2000, 1999 and 1998, respectively. Under the stock option plans and long-term incentive plan, the company is authorized to grant options and restricted stock for up to 4.3 million shares of common stock and has granted options and restricted stock on 2.1 million shares through December 31, 2000.

Had the company recorded compensation expense for the fair value of options granted consistent with SFAS No. 123, "Accounting for Stock-Based Compensation," net income would have been reduced on a pro forma basis by $529,000 in 2000, $498,000 in 1999, and $820,000 in 1998. On a pro forma basis, there would have been no effect on basic earnings per share for 2000, and diluted earnings per share would have been reduced by $.01. On a pro forma basis, basic and diluted earnings per share for 1999 and 1998 would have been reduced by $.01 and $.02, respectively.

A summary of the status of the stock option plans at December 31, 2000, 1999 and 1998, and changes during the years then ended are as follows:

	2000		1999		1998	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	1,427,262	$19.46	1,516,808	$19.17	594,180	$12.07
Granted	74,000	20.54	22,500	23.31	1,225,920	21.12
Forfeited	(84,135)	21.18	(57,966)	20.38	(37,875)	21.05
Exercised	(192,168)	11.84	(54,080)	11.95	(265,417)	11.98
Balance at end of year	1,224,959	20.61	1,427,262	19.46	1,516,808	19.17
Exercisable at end of year	129,763	$18.11	301,681	$13.89	333,261	$12.94

Exercise prices on options outstanding at December 31, 2000, range from $10.50 to $23.84 with a weighted average remaining contractual life of approximately 7 years.

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options are as follows:

	2000	1999	1998
Fair value of options at grant date	$5.07	$4.82	$2.40
Weighted average risk-free interest rate	6.76%	5.98%	4.78%
Weighted average expected price volatility	23.55%	22.03%	16.27%
Weighted average expected dividend yield	3.84%	4.22%	5.13%
Expected life in years	7	7	7

NOTE 8
INCOME TAXES

Income tax expense is summarized as follows:

Years ended December 31, *(In thousands)*	2000	1999	1998
Current:			
Federal	$ 27,865	$ 29,574	$ 28,256
State	5,188	3,874	5,880
Foreign	67	158	605
	33,120	33,606	34,741
Deferred:			
Income taxes --			
Federal	29,323	12,902	(14,214)
State	8,060	3,690	(2,067)
Investment tax credit	(853)	(888)	(975)
	36,530	15,704	(17,256)
Total income tax expense	$ 69,650	$ 49,310	$ 17,485

Components of deferred tax assets and deferred tax liabilities recognized in the company's Consolidated Balance Sheets at December 31 are as follows:

(In thousands)	2000	1999
Deferred tax assets:		
Accrued pension costs	$ 10,325	$ 10,898

Regulatory matters	7,650	14,562
Accrued land reclamation	1,941	2,803
Deferred investment tax credit	1,697	2,028
Other	18,213	16,892
Total deferred tax assets	39,826	47,183
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	264,635	218,355
Basis differences on natural gas and oil producing properties	36,763	17,163
Regulatory matters	3,554	6,785
Other	7,826	3,051
Total deferred tax liabilities	312,778	245,354
Net deferred income tax liability	$ (272,952)	$ (198,171)

The following table reconciles the change in the net deferred income tax liability from December 31, 1999, to December 31, 2000, to the deferred income tax expense included in the Consolidated Statements of Income:

	2000
(In thousands)	
Net change in deferred income tax liability from the preceding table	$ 74,781
Change in tax effects of income tax-related regulatory assets and liabilities	(150)
Deferred taxes associated with acquisitions	(38,101)
Deferred income tax expense for the period	$ 36,530

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 are as follows:

Years ended December 31,	2000 Amount	%	1999 Amount	%	1998 Amount	%
(Dollars in thousands)						
Computed tax at federal statutory rate	$ 63,237	35.0	$ 46,686	35.0	$ 18,057	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	8,044	4.4	5,921	4.4	2,312	4.5
Investment tax credit amortization	(853)	(.5)	(888)	(.6)	(975)	(1.9)
Depletion allowance	(1,631)	(.9)	(1,300)	(1.0)	(1,571)	(3.0)
Other items	853	.5	(1,109)	(.8)	(338)	(.7)
Total income tax expense	$ 69,650	38.5	$ 49,310	37.0	$ 17,485	33.9

NOTE 9

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 company's operations are conducted through six business segments. Substantially all of the company's operations are located within the United States. The electric business generates, transmits and distributes electricity and the natural gas distribution business distributes natural gas. These operations also supply related value-added products and services in the Northern Great Plains. The utility services business consists of a diversified infrastructure construction company specializing in electric, natural gas and telecommunication utility construction as well as interior industrial electrical, exterior lighting and traffic signalization. Utility services has engineering, design and build capability and provides related specialty equipment sales and rental services throughout most of the United States. The pipeline and energy services business provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems and provides energy-related marketing and management services. The natural gas and oil production business is engaged in natural gas and oil acquisition, exploration and production activities primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico. The construction materials and mining business mines and markets aggregates and related value-added construction materials products and services in the western United States, including Alaska and Hawaii, and it also operates lignite coal mines in Montana and North Dakota.

On September 28, 2000, the company announced an agreement to sell its coal operations to Westmoreland Coal Company for $28.8 million cash, excluding final settlement cost adjustments. The agreement is subject to various closing conditions and therefore will not be finalized unless and until the parties are satisfied that those conditions are met.

Segment information follows the same accounting policies as described in the Summary of Significant Accounting Policies. Segment information included in the accompanying Consolidated Balance Sheets as of December 31 and included in the Consolidated Statements of Income for the years then ended is as follows:

(In thousands)	2000	1999	1998
External operating revenues:			
Electric	$ 161,621	$ 154,869	$ 147,221
Natural gas distribution	233,051	157,692	154,147
Utility services	169,382	99,917	64,232
Pipeline and energy services	579,207	334,188	132,826
Natural gas and oil production	99,014	63,238	51,750
Construction materials and mining	617,564	455,939	331,988
Total external operating revenues	$ 1,859,839	$ 1,265,843	$ 882,164
Intersegment operating revenues:			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	---	---	---
Pipeline and energy services	57,641	49,344	47,906
Natural gas and oil production	39,302	15,156	10,092
Construction materials and mining(a)	13,832	13,966	14,463
Intersegment eliminations	(96,943)	(64,500)	(57,998)
Total intersegment operating revenues(a)	$ 13,832	$ 13,966	$ 14,463
Depreciation, depletion and amortization:			
Electric	$ 19,115	$ 18,375	$ 18,129
Natural gas distribution	8,399	7,348	7,150
Utility services	4,912	2,591	1,669
Pipeline and energy services	15,301	8,248	6,972
Natural gas and oil production	27,008	19,248	23,304
Construction materials and mining	36,153	26,008	20,562
Total depreciation, depletion and amortization	$ 110,888	$ 81,818	$ 77,786
Interest expense:			
Electric	$ 10,007	$ 9,692	$ 9,979
Natural gas distribution	4,142	3,614	3,728
Utility services	2,492	812	325
Pipeline and energy services	10,029	7,281	5,800
Natural gas and oil production	5,160	3,405	3,039
Construction materials and mining	16,415	11,202	7,402
Intersegment eliminations	(212)	---	---
Total interest expense	$ 48,033	$ 36,006	$ 30,273
Income taxes:			
Electric	$ 10,048	$ 8,678	$ 7,767
Natural gas distribution	3,544	1,443	2,681
Utility services	6,027	4,323	2,437
Pipeline and energy services	9,214	13,356	12,579
Natural gas and oil production	23,906	10,032	(23,134)
Construction materials and mining	16,911	11,478	15,155
Total income taxes	$ 69,650	$ 49,310	$ 17,485

Earnings on common stock:			
Electric	$ 17,733	$ 15,973	$ 13,908
Natural gas distribution	4,741	3,192	3,501
Utility services	8,607	6,505	3,272
Pipeline and energy services	10,494	20,972	18,651
Natural gas and oil production	38,574	16,207	(30,501)(b)
Construction materials and mining	30,113	20,459	24,499
Total earnings on common stock	$ 110,262	$ 83,308	$ 33,330
Capital expenditures:			
Electric	$ 15,788	$ 18,218	$ 13,035
Natural gas distribution	21,336	9,246	8,256
Utility services	42,633	16,052	18,343
Pipeline and energy services	69,006	35,123	17,603
Natural gas and oil production	173,441	64,294	100,572
Construction materials and mining	218,716	105,098	172,108
Net proceeds from sale or disposition of property	(11,000)	(16,660)	(4,275)
Total net capital expenditures	$ 529,920	$ 231,371	$ 325,642
Identifiable assets:			
Electric(c)	$ 305,099	$ 307,417	
Natural gas distribution(c)	192,854	131,294	
Utility services	123,451	67,755	
Pipeline and energy services	362,592	302,587	
Natural gas and oil production	410,207	255,416	
Construction materials and mining	874,299	655,499	
Corporate assets(d)	44,457	46,335	
Total identifiable assets	$ 2,312,959	$ 1,766,303	
Property, plant and equipment:			
Electric	$ 589,700	$ 581,090	
Natural gas distribution	227,742	185,797	
Utility services	39,865	21,876	
Pipeline and energy services	369,834	308,409	
Natural gas and oil production	513,419	343,157	
Construction materials and mining	755,563	601,952	
Less accumulated depreciation, depletion and amortization	895,109	794,105	
Net property, plant and equipment	$ 1,601,014	$ 1,248,176	

(a) In accordance with the provision of SFAS No. 71, intercompany coal sales are not eliminated.

(b) Reflects $39.9 million in noncash after-tax write-downs of natural gas and oil properties.

(c) Includes, in the case of electric and natural gas distribution property, allocations of common utility property.

(d) Corporate assets consist of assets not directly assignable to a business segment (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).

Capital expenditures for 2000, 1999 and 1998, related to acquisitions, in the preceding table include the following noncash transactions: issuance of the company's equity securities and the conversion of a note receivable to purchase consideration of $132.1 million in 2000; the issuance of the company's equity securities of $77.5 million in 1999; and the issuance of the company's equity securities, less treasury stock acquired, in 1998 of $138.8 million.

NOTE 10

ACQUISITIONS

In 2000, the company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses with operations in Alaska, California, Montana and Oregon; a coal bed natural gas development operation based in Colorado with related oil and gas leases and properties in Montana and Wyoming; utility services businesses based in California, Colorado, Montana and Ohio; a natural gas distribution business serving southeastern North Dakota and western Minnesota; and an energy services company based in Texas. The total purchase consideration for these businesses, consisting of the company's common stock, cash and the conversion of a note receivable to purchase consideration was $286.0 million.

On April 1, 2000, WBI Production, Inc., an indirect wholly owned subsidiary of the company, purchased substantially all of the assets of Preston Reynolds & Co., Inc. (Preston), a coal bed natural gas development operation, as previously discussed. Pursuant to the asset purchase and sale agreement, Preston may, but is not obligated to purchase, acquire and own an undivided 25 percent working interest (Seller's Option Interest) in oil and gas leases or properties acquired and/or generated by Redstone Gas Partners, LLC, a limited liability company controlled by the company. The Seller's Option Interest commences April 1, 2002 and terminates six months thereafter and requires Preston to pay WBI Production 25 percent of its capital investment, during the two year period subsequent to April 1, 2000, in the oil and gas leases or properties. WBI Production has the right, but not the obligation, to purchase Seller's Option Interest from Preston for an amount as specified in the agreement.

In 1999, the company acquired a number of businesses, none of which was individually material, including construction materials and mining companies with operations in California, Montana, Oregon and Wyoming; and utility services companies based in Montana and Oregon. The total purchase consideration for these businesses, consisting of the company's common stock and cash, was $81.9 million.

In March 1998, the company acquired Morse Bros., Inc. and S^2 - F Corp., privately held construction materials companies located in Oregon's Willamette Valley. The purchase consideration for such companies consisted of $98.2 million of the company's common stock and cash. Morse Bros., Inc. sells aggregate, ready-mixed concrete, asphalt, prestressed concrete and construction services in the Willamette Valley from Portland to Eugene. S^2 - F Corp. sells aggregate and construction services.

The company also acquired a number of other businesses in 1998, none of which was individually material, including construction materials and mining businesses in Oregon, utility services construction and engineering businesses in California and Montana and a natural gas marketing business in Kentucky. The total purchase consideration, consisting of the company's common stock and cash, for these businesses was $62.7 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. Final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date on certain of the above acquisitions. The results of operations of the acquired businesses are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented as such acquisitions were not material to the company's financial position or results of operations.

NOTE 11

EMPLOYEE BENEFIT PLANS

The company has noncontributory defined benefit pension plans and other postretirement benefit plans. There were no additional minimum pension liabilities required to be recognized as of December 31, 2000 and 1999. Changes in benefit obligation and plan assets for the years ended December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2000	1999	2000	1999
(In thousands)				
Change in benefit obligation:				
Benefit obligation at beginning of year	$180,997	$187,665	$65,939	$70,338
Service cost	4,561	4,894	1,307	1,451
Interest cost	14,174	12,573	4,946	4,720
Plan participants' contributions	---	---	677	617
Amendments	7,111	3,612	---	3,691
Actuarial (gain) loss	9,535	(17,134)	928	(11,047)
Benefits paid	(15,498)	(10,613)	(4,330)	(3,831)
Benefit obligation at end of year	200,880	180,997	69,467	65,939
Change in plan assets:				
Fair value of plan assets at beginning of year	276,459	251,194	47,147	39,543
Actual return on plan assets	875	35,874	(1,078)	5,223
Employer contribution	28	4	4,630	5,595
Plan participants' contributions	---	---	677	617
Benefits paid	(15,498)	(10,613)	(4,330)	(3,831)
Fair value of plan assets at end of year	261,864	276,459	47,046	47,147
Funded status	60,984	95,462	(22,421)	(18,792)
Unrecognized actuarial gain	(76,417)	(108,593)	(15,228)	(21,299)
Unrecognized prior service cost	16,271	10,206	---	---
Unrecognized net transition obligation (asset)	(3,387)	(4,402)	28,532	30,910
Accrued benefit cost	$(2,549)	$(7,327)	$(9,117)	$(9,181)

Weighted average assumptions for the company's pension and other postretirement benefit plans as of December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2000	1999	2000	1999
Discount rate	7.50%	7.75%	7.50%	7.75%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	5.00%	5.00%	5.00%	5.00%

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

	2000	1999
Health care trend rate	6.00%-7.50%	6.00%-8.00%
Health care cost trend rate - ultimate	5.00%-6.00%	5.00%-6.00%
Year in which ultimate trend rate achieved	1999-2004	1999-2004

Components of net periodic benefit cost for the company's pension and other postretirement benefit plans are as follows:

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	2000	1999	1998	2000	1999	1998
(In thousands)						
Components of net periodic benefit cost:						
Service cost	$ 4,561	$ 4,894	$ 4,509	$ 1,307	$ 1,451	$ 1,502
Interest cost	14,174	12,573	12,248	4,946	4,720	4,848
Expected return on assets	(19,927)	(17,489)	(15,892)	(3,267)	(2,807)	(2,395)
Amortization of prior service cost	1,047	842	848	---	---	---
Recognized net actuarial gain	(2,907)	(995)	(621)	(799)	(200)	(169)
Settlement gain	(700)	---	---	---	---	---
Amortization of net transition obligation (asset)	(997)	(997)	(994)	2,378	2,377	2,458
Net periodic benefit cost (income)	(4,749)	(1,172)	98	4,565	5,541	6,244
Less amount capitalized	(397)	(87)	79	369	463	628
Net periodic benefit expense (income)	$ (4,352)	$ (1,085)	$ 19	$ 4,196	$ 5,078	$ 5,616

The company has other postretirement benefit plans including health care and life insurance. 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 plan 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 the following effects at December 31, 2000:

	1 Percentage Point Increase	1 Percentage Point Decrease
(In thousands)		
Effect on total of service and interest cost components	$ 216	$ (196)
Effect on postretirement benefit obligation	$ 2,716	$ (2,627)

In addition to company-sponsored plans, certain union employees of Hawaiian Cement, an indirect wholly owned subsidiary of the company, are covered under a multi-employer defined benefit plan administered by a union. Amounts contributed to the multi-employer plan were $947,000, $818,000 and $755,000 in 2000, 1999 and 1998, respectively.

The company has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that provides for defined benefit payments upon the employee's retirement or to their beneficiaries upon death for a 15-year period. Investments consist of life insurance carried on plan participants which is payable to the company upon the employee's death. The cost of these benefits was $3.5 million, $3.3 million and $2.7 million in 2000, 1999 and 1998, respectively.

The company sponsors various defined contribution plans for eligible employees. Costs incurred by the company under these plans were $6.1 million in 2000, $4.4 million in 1999 and $3.1 million in 1998. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 12
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 is 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:

	2000	1999
(In thousands)		
Big Stone Station:		
Utility plant in service	$ 50,029	$ 49,889
Less accumulated depreciation	31,381	29,611
	$ 18,648	$ 20,278
Coyote Station:		
Utility plant in service	$ 122,111	$ 121,919
Less accumulated depreciation	63,741	60,350
	$ 58,370	$ 61,569

NOTE 13
REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

In June 1995, Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of the company, filed a general rate increase application with the Federal Energy Regulatory Commission (FERC). As a result of FERC orders issued after Williston Basin's application was filed, Williston Basin filed revised base rates in December 1995 with the FERC. Williston Basin began collecting such increase effective January 1, 1996, subject to refund. In July 1998, the FERC issued an order which addressed various issues including storage cost allocations, return on equity and throughput. In August 1998, Williston Basin requested rehearing of such order. In June 1999, the FERC issued an order approving and denying various issues addressed in Williston Basin's rehearing request, and also remanding the return on equity issue to an Administrative Law Judge for further proceedings. In July 1999, Williston Basin requested rehearing of certain issues which were contained in the June 1999 FERC order. In September 1999, the FERC granted Williston Basin's request for rehearing with respect to the return on equity issue but also ordered Williston Basin to issue interim refunds prior to the final determination in this proceeding. As a result, in October 1999, Williston Basin issued refunds to its customers totaling $11.3 million, all from amounts which had previously been reserved. In December 1999, a hearing was held before the FERC regarding the return on equity issue. On April 27, 2000, the Administrative Law Judge issued an Initial Decision regarding the remanded return on equity issue. On August 15, 2000, Williston Basin filed a stipulation and agreement for the purpose of resolving the rate and refund matters at issue with the FERC. On November 21, 2000, the FERC issued its order accepting the August 15, 2000 stipulation and agreement. As a result, on December 28, 2000, Williston Basin issued refunds to its customers totaling $13.0 million, all from amounts which had previously been reserved.

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.

Reserves have been provided for a portion of the revenues that have been collected subject to refund with respect to pending regulatory proceedings and to reflect future resolution of certain issues with the FERC. Based on the November 21, 2000 FERC order referenced above, Williston Basin, in the fourth quarter of 2000, determined that reserves it had previously established exceeded its expected refund obligation and, accordingly, reversed reserves and recognized in income $6.7 million after tax. Williston Basin, in the second quarter of 1999, determined that reserves it had previously established in relation to a 1992 general natural gas rate change application and the 1995 general rate increase application exceeded its expected refund obligation and, accordingly, reversed reserves and recognized in income $4.4 million after tax. Williston Basin believes that its remaining reserves are adequate based on its assessment of the ultimate outcome of the application filed in December 1999.

NOTE 14

COMMITMENTS AND CONTINGENCIES

Litigation

In March 1997, 11 natural gas producers filed suit in North Dakota Northwest Judicial District Court (North Dakota District Court) against Williston Basin and the company. The natural gas producers had processing agreements with Koch Hydrocarbon Company (Koch). Williston Basin and the company had natural gas purchase contracts with Koch. The natural gas producers alleged they were entitled to damages for the breach of Williston Basin's and the company's contracts with Koch although no specific damages were stated. A similar suit was filed by Apache Corporation (Apache) and Snyder Oil Corporation (Snyder) in North Dakota District Court in December 1993. The North Dakota Supreme Court in December 1999 affirmed the North Dakota District Court decision dismissing Apache's and Snyder's claims against Williston Basin and the company. Based in part upon the decision of the North Dakota Supreme Court affirming the dismissal of the claims brought by Apache and Snyder, Williston Basin and the company filed motions for summary judgment to dismiss the claims of the 11 natural gas producers. The motions for summary judgment were granted by the North Dakota District Court on July 3, 2000. The company is awaiting entry of a final judgment on the July 3, 2000 order granting the motions for summary judgment.

In July 1996, Jack J. Grynberg (Grynberg) filed suit in United States District Court for the District of Columbia (U.S. District Court) against Williston Basin and over 70 other natural gas pipeline companies. Grynberg, acting on behalf of the United States under the Federal False Claims Act, alleged improper measurement of the heating content or volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. In March 1997, the U.S. District Court dismissed the suit without prejudice and the dismissal was affirmed by the D.C. Circuit Court in October 1998. In June 1997, Grynberg filed a similar Federal False Claims Act suit against Williston Basin and Montana-Dakota and filed over 70 other separate similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. In April 1999, the United States Department of Justice decided not to intervene in these cases. In response to a motion filed by Grynberg, the Judicial Panel on Multidistrict Litigation consolidated all of these cases in the Federal District Court of Wyoming (Federal District Court). Oral argument on motions to dismiss was held before the Federal District Court on March 17, 2000. Williston Basin and Montana-Dakota are awaiting a decision from the Federal District Court.

The Quinque Operating Company (Quinque), on behalf of itself and subclasses of gas producers, royalty owners and state taxing authorities, instituted a legal proceeding in State District Court for Stevens County, Kansas, against over 200 natural gas transmission companies and producers, gatherers, and processors of natural gas, including Williston Basin and Montana-Dakota. The complaint, which was served on Williston Basin and Montana-Dakota in September 1999, contains allegations of improper measurement of the heating content and volume of all natural gas measured by the defendants other than natural gas produced from federal lands. In response to a motion filed by the defendants in this suit, the Judicial Panel on Multidistrict Litigation transferred the suit to the Federal District Court for inclusion in the pretrial proceedings of the Grynberg suit.

Williston Basin and Montana-Dakota believe the claims of Grynberg and Quinque are without merit and intend to vigorously contest these suits.
The company is also 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 there is no pending legal proceeding against or involving the company, except those discussed above, for which the outcome is likely to have a material adverse effect upon the company's financial position or results of operations.

Environmental matters
In December 2000, Morse Bros., Inc. (MBI), an indirect wholly owned subsidiary of the company, was named by the United States Environmental Protection Agency (EPA) as a Potentially Responsible Party in connection with the cleanup of a commercial property site, now owned by MBI, and part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon State Department of Environmental Quality and other information available, MBI does not believe it is a Responsible Party. In addition, MBI intends to seek indemnity for any and all liabilities incurred in relation to the above matters from Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, pursuant to the terms of their sale agreement.

Electric purchased power commitments
Through October 31, 2006, Montana-Dakota has contracted to purchase 66,400 kW of participation power annually from Basin Electric Power Cooperative. In addition, Montana-Dakota, under a power supply contract through December 31, 2006, is purchasing up to 55,000 kW of capacity annually from Black Hills Power and Light Company.

NOTE 15
QUARTERLY DATA (UNAUDITED)
The following unaudited information shows selected items by quarter for the years 2000 and 1999:

(In thousands, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2000				
Operating revenues	$371,989	$362,979	$530,834	$607,869
Operating expenses	342,559	321,900	454,811	537,414
Operating income	29,430	41,079	76,023	70,455
Net income	13,364	21,126	39,992	36,546
Earnings per common share:				
Basic	.23	.35	.63	.57
Diluted	.23	.35	.63	.56
Weighted average common shares outstanding:				
Basic	57,051	59,987	62,975	64,289
Diluted	57,188	60,212	63,345	64,817
1999				
Operating revenues	$ 259,046	$ 290,267	$ 375,591	$ 354,905
Operating expenses	233,585	254,619	321,535	310,319
Operating income	25,461	35,648	54,056	44,586
Net income	12,721	17,796	29,098	24,465
Earnings per common share:				
Basic	.24	.33	.53	.43
Diluted	.23	.33	.52	.42
Weighted average common shares outstanding:				
Basic	53,147	53,373	54,995	56,898
Diluted	53,420	53,603	55,278	57,127

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

NOTE 16
NATURAL GAS AND OIL ACTIVITIES (UNAUDITED)

Fidelity Exploration & Production Company (Fidelity), an indirect wholly owned subsidiary of the company, is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's operations include the acquisition of producing properties with potential development opportunities, exploratory drilling and the operation of natural gas production properties. Fidelity shares revenues and expenses from the development of specified properties located primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico in proportion to its interests.

Fidelity owns in fee or holds natural gas leases for the properties it operates in Colorado, Montana and North Dakota. These rights are in the Bonny Field located in eastern Colorado, the Cedar Creek Anticline in southeastern Montana and southwestern North Dakota, and in the Bowdoin area located in north-central Montana. In 2000, coal bed natural gas reserves in the Powder River Basin of Wyoming and Montana were acquired. These acquisitions include over 210,000 net acres under lease.

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

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

	2000	1999	1998
(In thousands)			
Subject to amortization	$ 416,881	$ 319,448	$ 266,301
Not subject to amortization	94,856	23,464	22,153
Total capitalized costs	511,737	342,912	288,454
Less accumulated depreciation, depletion and amortization	155,198	129,211	111,472
Net capitalized costs	$ 356,539	$ 213,701	$ 176,982

NOTE: Net capitalized costs as of December 31, 1998, reflect noncash write-downs of the company's natural gas and oil properties as discussed in Note 1.

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

Years ended December 31,	2000	1999	1998
(In thousands)			
Acquisitions	$ 68,858	$ 30,842	$ 63,419
Exploration	34,839	11,010	15,976
Development	69,051	21,822	21,148
Total capital expenditures	$ 172,748	$ 63,674	$ 100,543

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

Years ended December 31,	2000	1999	1998
(In thousands)			
Revenues	$ 128,217	$ 75,327	$ 61,831
Production costs	33,919	25,402	19,419
Depreciation, depletion and amortization	26,739	19,136	23,050
Write-downs of natural gas and oil properties (Note 1)	---	---	66,000
Pretax income (loss)	67,559	30,789	(46,638)
Income tax expense (benefit)	25,835	11,815	(19,268)
Results of operations for producing activities	$ 41,724	$ 18,974	$(27,370)

The following table summarizes the company's estimated quantities of proved natural gas and oil reserves at December 31, 2000, 1999 and 1998, and reconciles the changes between these dates. Estimates of economically recoverable natural gas and oil reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

(In thousands of Mcf/barrels)	2000 Natural Gas	2000 Oil	1999 Natural Gas	1999 Oil	1998 Natural Gas	1998 Oil
Proved developed and undeveloped reserves:						
Balance at beginning of year	268,900	14,700	243,600	11,500	184,900	14,900
Production	(29,200)	(1,900)	(24,700)	(1,800)	(20,700)	(1,900)
Extensions and discoveries	51,300	1,600	21,800	800	21,300	200
Purchases of proved reserves	23,200	100	38,200	700	56,600	2,000
Sales of reserves in place	---	(100)	(9,300)	(400)	(100)	---
Revisions to previous estimates due to improved secondary recovery techniques and/or changed economic conditions	(4,400)	700	(700)	3,900	1,600	(3,700)
Balance at end of year	309,800	15,100	268,900	14,700	243,600	11,500

Proved developed reserves:		
January 1, 1998	163,800	14,500
December 31, 1998	193,000	10,700
December 31, 1999	213,400	13,300
December 31, 2000	263,400	14,200

All of the company's interests in natural gas and oil reserves are located in the United States and in the Gulf of Mexico.
The standardized measure of the company's estimated discounted future net cash flows of total proved reserves associated with its various natural gas and oil interests at December 31 is as follows:

(In thousands)	2000	1999	1998
Future net cash flows before income taxes	$ 2,349,500	$ 492,000	$ 246,700
Future income tax expense	827,000	131,500	40,500
Future net cash flows	1,522,500	360,500	206,200
10% annual discount for estimated timing of cash flows	601,200	131,400	81,100
Discounted future net cash flows relating to proved natural gas and oil reserves	$ 921,300	$ 229,100	$125,100

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

(In thousands)	2000	1999	1998
Beginning of year	$ 229,100	$ 125,100	$139,000
Net revenues from production	(94,300)	(49,900)	(42,400)

Change in net realization	861,700	123,100	(70,500)
Extensions, discoveries and improved recovery, net of future production-related costs	288,700	33,500	18,200
Purchases of proved reserves	93,200	57,700	51,000
Sales of reserves in place	(1,500)	(14,700)	(100)
Changes in estimated future development costs, net of those incurred during the year	3,400	(9,800)	(16,600)
Accretion of discount	31,200	16,700	18,600
Net change in income taxes	(412,300)	(59,800)	30,100
Revisions of previous quantity estimates	(79,200)	7,400	(1,600)
Other	1,300	(200)	(600)
Net change	692,200	104,000	(13,900)
End of year	$ 921,300	$ 229,100	$ 125,100

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end natural gas prices and oil prices except in those instances where future natural gas or oil sales are covered by physical or derivative contract terms providing for higher or lower amounts. Future development and production costs attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying statutory tax rates (adjusted for permanent differences and tax credits) to estimated net future pretax cash flows.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of natural gas and oil properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of natural gas and oil prices over the remaining reserve lives may vary significantly from current prices.

NOTE 17
INVESTMENT IN SUBSIDIARY
The Respondent, through its wholly-owned subsidiary, Centennial Energy Holdings, Inc., owns WBI Holdings, Inc., Knife River Corporation and Utility Services, Inc.

As required by the Federal Energy Regulatory Commission 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 generally accepted accounting principles. If generally accepted accounting principles were followed, utility plant, other property and investments would increase by $517,845,533 and $371,553,478; current and accrued assets would increase by $347,911,277 and $263,169,598; deferred debits would increase by $161,152,427 and $84,043,514; preferred stock would decrease by $100,000 and $100,000; long-term debt would increase by $554,322,288 and $389,649,471; other noncurrent liabilities and current and accrued liabilities would increase by $173,105,095 and $105,374,079; deferred credits would increase by $303,207,667 and $227,468,852 as of December 31, 2000 and 1999, respectively. Furthermore, operating revenues would increase by $1,478,998,298 and $967,248,297; and operating expenses, excluding income taxes, would increase by $1,310,284,540 and $849,912,662 for the year ended December 31, 2000 and 1999, respectively. In addition, net cash provided by operating activities would increase by $169,142,000; net cash used in investing activities would increase by $262,429,000; net cash provided by financing activities would increase by $53,674,000; and the net change in cash and cash equivalents would be a decrease of $39,613,000 for the year ended December 31, 2000. Reporting its subsidiary investment using the equity method rather than generally accepted accounting principles has no effect on net income or retained earnings.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2000

	Account Number & Title		Last Year	This Year	% Change
1		**Intangible Plant**			
2					
3	301	Organization			
4	302	Franchises & Consents			
5	303	Miscellaneous Intangible Plant	$1,128,233	$1,432,789	26.99%
6					
7		**TOTAL Intangible Plant**	$1,128,233	$1,432,789	26.99%
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: 2000

	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: 2000

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Distribution Plant**			
3					
4	374	Land & Land Rights	$34,947	$34,947	
5	375	Structures & Improvements	190,323	190,593	
6	376	Mains	19,822,289	20,389,742	2.86%
7	377	Compressor Station Equipment			
8	378	Meas. & Reg. Station Equipment-General	539,187	536,710	-0.46%
9	379	Meas. & Reg. Station Equipment-City Gate	129,124	129,124	
10	380	Services	10,196,342	10,533,388	3.31%
11	381	Meters	9,112,675	9,589,090	5.23%
12	382	Meter Installations			
13	383	House Regulators	1,323,366	1,379,530	4.24%
14	384	House Regulator Installations			
15	385	Industrial Meas. & Reg. Station Equipment	111,237	112,646	1.27%
16	386	Other Prop. on Customers' Premises 1/	161,799	161,799	
17	387	Other Equipment	786,030	835,048	6.24%
18					
19		**TOTAL Distribution Plant**	$42,407,319	$43,892,617	3.50%
20					
21		**General Plant**			
22					
23	389	Land & Land Rights	$26,744	$26,744	
24	390	Structures & Improvements	280,773	299,252	6.58%
25	391	Office Furniture & Equipment	132,900	258,007	94.14%
26	392	Transportation Equipment	1,588,803	1,834,625	15.47%
27	393	Stores Equipment	48,508	48,508	
28	394	Tools, Shop & Garage Equipment 1/	844,653	886,145	4.91%
29	395	Laboratory Equipment	97,427	97,411	-0.02%
30	396	Power Operated Equipment	1,229,602	1,179,910	-4.04%
31	397	Communication Equipment	345,266	349,358	1.19%
32	398	Miscellaneous Equipment	44,499	44,354	-0.33%
33	399	Other Tangible Property			
34					
35		**TOTAL General Plant**	$4,639,175	$5,024,314	8.30%
36					
37		**Common Plant**			
38					
39	389	Land & Land Rights	$185,358	$181,506	-2.08%
40	390	Structures & Improvements	2,222,343	2,227,673	0.24%
41	391	Office Furniture & Equipment	1,367,305	1,078,638	-21.11%
42	392	Transportation Equipment	566,922	619,979	9.36%
43	393	Stores Equipment	9,078	9,191	1.24%
44	394	Tools, Shop & Garage Equipment	117,414	131,638	12.11%
45	396	Power Operated Equipment		13,890	100.00%
46	397	Communication Equipment	419,680	491,017	17.00%
47	398	Miscellaneous Equipment	61,858	63,652	2.90%
48					
49		**TOTAL Common Plant**	$4,949,958	$4,817,184	-2.68%
50					
51		**TOTAL Gas Plant in Service**	$53,124,685	$55,166,904	3.84%

1/ Includes gas plant leased to others.

MONTANA DEPRECIATION SUMMARY

Year: 2000

	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	$43,892,617	$26,272,894	$27,809,866	3.98%
7	General	5,076,230	2,472,123	2,477,005	1.50%
8	Common	6,198,057	2,436,711	2,244,321	5.21%
9	**TOTAL**	$55,166,904	$31,181,728	$32,531,192	3.89%

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)	$336,111	$338,936	0.84%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	163 Stores Expense Undistributed			
15				
16	**TOTAL Materials & Supplies**	$336,111	$338,936	0.84%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	D95.7.90		12.00%	
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	Other				
8	**TOTAL**				10.913%
9					
10	Actual at Year End				
11					
12	Common Equity		44.756%	12.000%	5.371%
13	Preferred Stock		4.788%	4.632%	0.222%
14	Long Term Debt		50.456%	9.388%	4.737%
15	Other				
16	**TOTAL**		100.000%		10.330%

STATEMENT OF CASH FLOWS

Year: 2000

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$84,079,784	$111,028,298	32.05%
5	Depreciation	25,724,554	27,513,912	6.96%
6	Amortization	1,621,351	1,528,891	-5.70%
7	Deferred Income Taxes - Net	846,736	(768,308)	-190.74%
8	Investment Tax Credit Adjustments - Net	(888,062)	(852,655)	-3.99%
9	Change in Operating Receivables - Net	(8,094,643)	(24,602,540)	-203.94%
10	Change in Materials, Supplies & Inventories - Net	(970,731)	4,236,915	536.47%
11	Change in Operating Payables & Accrued Liabilities - Net	1,771,633	22,734,416	1183.25%
12	Change in Other Regulatory Assets	563,557	1,165,973	106.90%
13	Change in Other Regulatory Liabilities	(4,442,433)	175,124	103.94%
14	Allowance for Funds Used During Construction (AFUDC)	(419,934)	(157,410)	-62.52%
15	Change in Other Assets & Liabilities - Net	11,911,018	(16,394,017)	-237.64%
16	Less Undistributed Earnings from Subsidiary Companies	(64,143,724)	(87,788,729)	36.86%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$47,559,106	$37,819,870	-20.48%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($28,075,022)	($33,966,186)	20.98%
23	Acquisition of Other Noncurrent Assets	401,633	3,468,361	763.56%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(80,704,819)	(141,457,074)	75.28%
26	Contributions and Advances from Affiliates	28,591,800	34,649,500	21.19%
27	Disposition of Investments in and Advances to Affiliates	2,000,000	3,000,000	50.00%
28	Other Investing Activities: Depreciation on Nonutility Plant	8,465	10,240	20.97%
29	**Net Cash Provided by/(Used in) Investing Activities**	($77,777,943)	($134,295,159)	72.66%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt			
34	Preferred Stock			
35	Common Stock	$80,704,795	$154,448,288	91.37%
36	Other:			
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper			
39	Payment for Retirement of:			
40	Long-Term Debt	(300,000)	(303,176)	1.06%
41	Preferred Stock	(100,000)	(100,000)	0.00%
42	Common Stock			
43	Other:			
44	Net Decrease in Short-Term Debt	(2,000,000)	(5,000,000)	150.00%
45	Dividends on Preferred Stock	(771,708)	(766,607)	-0.66%
46	Dividends on Common Stock	(45,321,381)	(53,182,971)	17.35%
47	Other Financing Activities (explained on attached page)			
48	**Net Cash Provided by (Used in) Financing Activities**	$32,211,706	$95,095,534	195.22%
49				
50	**Net Increase/(Decrease) in Cash and Cash Equivalents**	$1,992,869	($1,379,755)	-169.23%
51	**Cash and Cash Equivalents at Beginning of Year**	$6,475,581	$8,468,450	30.78%
52	**Cash and Cash Equivalents at End of Year**	$8,468,450	$7,088,695	-16.29%

LONG TERM DEBT

Year: 2000

	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	8.25 % Secured MTN, Series A	04/92	04/07	$30,000,000	$26,111,796	$30,000,000	8.25%	$3,053,100	10.18%
2	8.60 % Secured MTN, Series A	04/92	04/12	35,000,000	28,906,532	35,000,000	8.60%	3,857,000	11.02%
3	6.52 % Secured MTN, Series A	09/97	10/04	15,000,000	14,082,923	15,000,000	6.52%	1,171,650	7.81%
4	6.71 % Secured MTN, Series A	09/97	10/09	15,000,000	13,488,404	15,000,000	6.71%	1,229,250	8.20%
5	5.83 % Secured MTN, Series A	09/98	10/08	15,000,000	14,813,914	15,000,000	5.83%	912,900	6.09%
6	Grant County 6.20 % PCN	03/74	03/04	5,600,000	5,427,042	2,800,000	6.20%	183,568	6.56%
7	Mercer County 6.65 % 2/	06/92	06/22	15,000,000	14,061,276	15,000,000	6.65%	1,093,200	7.29%
8	Richland County 6.65 % 2/	06/92	06/22	3,250,000	3,063,677	3,250,000	6.65%	235,398	7.24%
9	Morton County 6.65 % 2/	06/92	06/22	2,600,000	2,420,986	2,600,000	6.65%	190,944	7.34%
10	Term Loan 3/								
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26	**TOTAL**			$136,450,000	$122,376,550	$133,650,000		$11,927,010	8.92%

1/ Includes interest expense, bond discount expense, debt issuance expense and loss on bond reacquistion and redemption.
2/ Pollution Control Refunding Revenue Bonds.
3/ The company has $40 million in term loans which were outstanding at year end.
The average 2000 term loan rate was 9.282%.

PREFERRED STOCK

Year: 2000

	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	05/61	50,000	100	102	4,947,548	5.29%	1,500,000	79,275	5.29%
4										
5										
6										
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29										
30										
31										
32	**TOTAL**					$19,947,548		$16,500,000	$764,275	4.63%

1/ Plus accrued dividends.

COMMON STOCK

Year: 2000

		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share 1/	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio 2/
1									
2									
3									
4	January	57,056,646	$11.81						
5									
6	February	57,056,646	11.67						
7									
8	March	57,056,646	11.76	$0.23	$0.2100	8.70%	$21.44	$17.63	13.8 X
9									
10	April	58,322,683	11.95						
11									
12	May	61,148,770	12.10						
13									
14	June	61,280,227	12.27	0.35	0.2100	40.00%	23.25	20.38	14.2 X
15									
16	July	62,705,861	12.56						
17									
18	August	63,512,502	12.69						
19									
20	September	64,226,880	13.03	0.63	0.2200	65.08%	30.06	21.56	18.0 X
21									
22	October	64,434,926	13.31						
23									
24	November	64,681,458	13.29						
25									
26	December	65,028,046	13.55	0.57	0.2200	61.40%	33.00	27.44	18.1 X
27									
28									
29									
30	TOTAL Year End	65,028,046	$13.55	$1.78	$0.8600	51.69%			18.1 X

1/ Basic earnings per share.
2/ Calculated on 12 months ended using closing stock price.

MONTANA COMPOSITE STATISTICS

Year: 2000

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$51,156
5	107	Construction Work in Progress	194
6	114	Plant Acquisition Adjustments	
7	104	Plant Leased to Others	17
8	105	Plant Held for Future Use	
9	154, 156	Materials & Supplies	339
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	32,531
12	252	Contributions in Aid of Construction	277
13			
14		**NET BOOK COSTS**	$18,898
15			
16		Revenues & Expenses (000 Omitted)	
17			
18	400	Operating Revenues	$64,406
19			
20	403 - 407	Depreciation & Amortization Expenses	$2,145
21		Federal & State Income Taxes	1,087
22		Other Taxes	2,010
23		Other Operating Expenses	56,662
24		TOTAL Operating Expenses	$61,904
25			
26		Net Operating Income	$2,502
27			
28		Other Income	506
29		Other Deductions	1,466
30			
31		**NET INCOME**	$1,542
32			
33		Customers (Intrastate Only)	
34			
35		Year End Average:	
36		Residential	61,864
37		Firm General	7,557
38		Small Interruptible	36
39		Large Interruptible	5
40			
41		**TOTAL NUMBER OF CUSTOMERS**	69,462
42			
43		Other Statistics (Intrastate Only)	
44			
45		Average Annual Residential Use (Dkt))	93
46		Average Annual Residential Cost per (Dkt) ($) * 1/	$7.81
47		* Avg annual cost = [(cost per Dkt x annual use) + (mo. svc chrg x 12)]/annual use	
48		Average Residential Monthly Bill	$49.14
49		Gross Plant per Customer	$736

1/ Reflects cost per dk effective December 1, 2000.

MONTANA CUSTOMER INFORMATION

Year: 2000

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	219	134	23		157
2	Billings	89,847	38,511	3,690		42,201
3	Bridger	745	404	63		467
4	Crow Agency	1,552	309	62		371
5	Edgar	Not Available	104	8		112
6	Fromberg	486	270	22		292
7	Hardin	3,384	1,239	199		1,438
8	Joliet	575	344	38		382
9	Laurel	6,255	3,222	260		3,482
10	Park City	870	459	22		481
11	Pryor	628	82	12		94
12	Rockvale	Not Available	59	4		63
13	Silesia	Not Available	32	2		34
14	Warren	Not Available		1		1
15	Alzada	Not Available	7	6		13
16	Baker	1,695	750	174		924
17	Carlyle	Not Available	8	1		9
18	Fort Peck	240	121	11		132
19	Fairview	709	348	51		399
20	Forsyth	1,944	880	144		1,024
21	Frazer	452	103	14		117
22	Glasgow	3,253	1,655	292		1,947
23	Glendive	4,729	2,970	414		3,384
24	Hinsdale	Not Available	115	17		132
25	Ismay	26	10	4		14
26	Malta	2,120	1,012	202		1,214
27	Miles City	8,487	3,876	512		4,388
28	Nashua	325	186	21		207
29	Poplar	911	868	128		996
30	Richey	189	116	26		142
31	Rosebud	Not Available	50	6		56
32	Saco	224	45	9		54
33	Savage	Not Available	153	16		169
34	Sidney	4,774	2,243	382		2,625
35	Terry	611	316	66		382
36	St. Marie	183	143	11		154
37	Wibaux	567	218	55		273
38	Whitewater	Not Available	36	8		44
39	Wolf Point	2,663	1,403	207		1,610
40	MT Oil Fields	Not Available	2	4		6
41	**TOTAL Montana Customers**	138,663	62,803	7,187		69,990

1/ 2000 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 2000

	Department	Year Beginning	Year End	Average
1	Electric	24	22	23
2	Gas	40 (2)	40	40 (1)
3	Accounting	25 (1)	23	24 (1)
4	Marketing/Communications	3	6	5
5	Management	7	7	7
6	Power	24	26	25
7	Service 2/	55 (5)	54 (5)	54 (5)
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41				
42	**TOTAL Montana Employees**	178 (8)	178 (5)	178 (7)

1/ Parentheses denotes part-time.

2/ Reflects service employees such as meter readers, service dispatchers and servicemen.

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

Year: 20

	Project Description	Total Company	Total Montana
1	Projects>$1,000,000		
2			
3	Gas-General		
4	Constuct office/service center building in Rapid City, SD	$2,952,171	$0
5			
6	Common-General		
7	Develop Geospacial Enterprise Management System	1,581,282	384,665
8			
9			
10			
11			
12	Other Projects<$1,000,000		
13			
14	Electric		
15	Production	$3,128,140	$775,624
16	Transmission:		
17	Integrated	1,029,357	191,010
18	Direct	571,628	87,546
19	Distribution	6,111,743	1,006,294
20	General	1,081,105	153,743
22	Common:		
23	General Office	1,529,141	354,698
24	Other Direct	782,015	170,282
25	Total Electric	$14,233,129	$2,739,197
26			
27	Gas		
28	Distribution	$6,216,552	$1,895,597
29	General	1,553,287	361,803
30	Common:		
31	General Office	945,197	247,420
32	Other Direct	432,081	187,316
33	Total Gas	$9,147,117	$2,692,136
34			
35			
36			
37			
38			
39			
40			
41			
42			
43	TOTAL	$27,913,699	$5,815,998

1/ Allocated to Montana.

2/ Directly assigned to Montana.

: 31

01

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TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2000

	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: 2000

	Total Company			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	3	264,119	6,921,790
2	February	10	248,485	5,443,574
3	March	9	193,059	4,280,345
4	April	14	168,891	3,126,910
5	May	12	135,468	2,345,148
6	June	1	92,659	1,765,711
7	July	12	60,331	1,539,236
8	August	14	58,102	1,540,392
9	September	22	135,259	2,170,512
10	October	5	170,161	3,699,291
11	November	13	248,544	6,419,651
12	December	11	309,923	8,026,981
13	**TOTAL**			47,279,541

	Montana			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
14	January	3	72,856	1,994,402
15	February	10	73,158	1,618,304
16	March	9	54,071	1,247,847
17	April	2	44,152	768,465
18	May	12	44,875	836,524
19	June	1	34,147	613,039
20	July	12	23,628	550,093
21	August	14	25,244	538,384
22	September	22	48,603	813,440
23	October	5	54,548	1,266,752
24	November	12	84,517	2,115,490
25	December	10	97,088	2,378,742
26	**TOTAL**			14,741,482

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 32 Continued

Year: 2000

STORAGE SYSTEM - TOTAL COMPANY & MONTANA

		Total Company						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
1	January	1	3	629	119,919	1,292	2,387,862	
2	February	23	10	7,362	107,606	29,952	1,431,356	
3	March	5	9	14,069	80,327	104,576	752,938	
4	April	22	14	34,634	69,260	290,527	506,142	
5	May	21	12	44,888	24,007	1,065,016	32,284	
6	June	30	1	54,464	308	1,348,583	860	
7	July	22	28	57,511	99	1,597,038	602	
8	August	1	7	56,348	74	1,470,556	141	
9	September	3	22	50,301	31,242	963,217	81,367	
10	October	18	5	27,315	48,990	337,570	241,522	
11	November	4	12	8,431	98,590	21,259	1,883,685	
12	December	25	20	1,280	168,823	7,681	3,444,095	
13	**TOTAL**					7,237,267	10,762,854	

		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**							

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 33

SOURCES OF GAS SUPPLY

Year: 2000

	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					
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25					
26					
27					
28					
29	1/ Supplier information is proprietary and confidential.				
30					
31					
32					
33	**Total Gas Supply Volumes**	33,543,763	32,149,990	$1.945	$3.262

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 34

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2000

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings **(Mcf or Dkt)**	Achieved Savings **(Mcf or Dkt)**	Difference
1							
2	NONE						
3							
4							
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30							
31							
32	**TOTAL**						

MONTANA CONSUMPTION AND REVENUES

Year: 2000

	Sales of Gas	Operating Revenues Current Year	Operating Revenues Previous Year	DK Sold Current Year	DK Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year 1/
1	Residential	$36,482,551	$29,785,499	5,780,444	5,576,189	61,864	62,677
2	Firm General	21,118,367	16,769,075	3,449,256	3,263,979	7,557	7,556
3	Small Interruptible	423,462	299,111	70,903	65,027	4	5
4	Large Interruptible		1,623		507		
5							
6							
7							
8							
9							
10							
11	**TOTAL**	$58,024,380	$46,855,308	9,300,603	8,905,702	69,425	70,238
12							
13							

	Transportation of Gas	Operating Revenues Current Year	Operating Revenues Previous Year	BCF Transported Current Year	BCF Transported Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year 1/
18							
19	Utilities						
20	Small Interruptible	$454,683	$537,940	0.8	0.9	32	33
21	Large Interruptible	554,613	403,335	4.0	3.1	5	5
22	Firm	12,438	11,928				
23							
24	**TOTAL**	$1,021,734	$953,203	4.8	4.0	37	38

1/ Reflects bills divided by twelve.