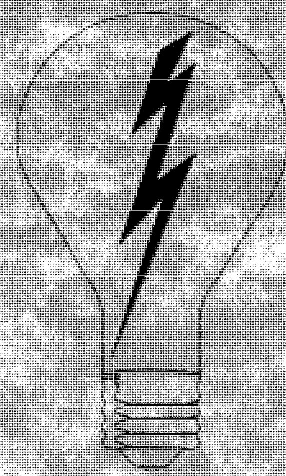
YEAR 1999

ANNUAL REPORT
OF

Montana-Dakota Utilities Company

ELECTRIC UTILITY



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

Electric Annual Report

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Electric Annual Report

Instructions

General

1. A Microsoft EXCEL 97 workbook of the annual report is being provided on computer disk for your convenience. The workbook contains the schedules of the annual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1". By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell.

2. The workbook contains input sections that are unprotected, and non-input sections that are protected. Cell protection can be disabled or enabled through "TOOLS – PROTECTION – UNPROTECT SHEET" on your toolbar. Formulas and checks are built into most of the templates.

3. Use of the disk is optional. The disk and the report cover shall be returned when the report is filed. There are macros built into the workbook to assist you with the report. An explanation of the macros is on the "Control" worksheet at the front of the workbook. The explanations start at cell A1.

4. All forms must be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed. The orientation and margins are set up on each individual worksheet and should print on one page. If you elect not to use the disk, please format your reports to fit on one 8.5'' by 11'' page with the left binding edge (top if landscaped) set at .85'', the right edge (bottom if landscaped) set at .4'', and the remaining two margins at .5''. You may select specific schedules to print – See the worksheet "CONTROL".

5. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses (   ).

6. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

7. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

8. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

9. All companies owned by another company shall attach a corporate structure chart of the holding company.

10. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

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

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

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

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

12. FERC Form-1 sheets may not be substituted in lieu of completing annual report schedules.

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

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 101 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

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

Schedule 12

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

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form using FASB 87 and 132 guidelines.

3. Interest rate percentages shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 15 and 16. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 15 and 16. All assumptions used in quantifying cost containment results shall be disclosed.

2. Schedule 15 shall be filled out using FASB 106 and 132 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

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

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

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

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

3. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

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

Schedule 31

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

Schedule 32

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

Schedule 34

1. The following categories shall be used in the Type column: Thermal, Hydro, Nuclear, Solar, Wind, GeoThermal, Qualifying Facility (QF), Independent Power Producer (IPP), Off System Purchases, or Other. Spot market purchases shall be separately identified. Entries for the Other category shall be listed as separate line items and include a description.
   Note: For Off System Purchases, the Utility/Company whom the purchases are being made from shall be entered in the Plant Name column, the termination date of the purchased power contract shall be entered in the Location column.

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

Schedule 35

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

IDENTIFICATION

Year: 1999

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:	C. Wayne Fox
5a.	Telephone Number:	(701) 222-7637

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	Lester H. Loble II, Bismarck, ND	-
4	Stanley E. Wingate, Bismarck, ND 2/	-
5	Bruce T. Imsdahl, Bismarck, ND	-
6	Douglas C. Kane, Bismarck, ND	-
7	Warren L. Robinson, Bismarck, ND	-
8		
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	2/ David L. Goodin replaced Stanley E. Wingate effective 01/01/2000.	
20		

Officers

Year: 1999

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President and Chief	Executive	Ronald D. Tipton
2	Executive Officer		
3			
4	Vice President	Regulatory Affairs and	C. Wayne Fox
5		General Services	
6			
7	Vice President	Energy Supply	Bruce T. Imsdahl
8			
9	Assistant Vice President	Gas Supply	Donald F. Klempel
10			
11	Vice President	Marketing and	Ronald G. Skarphol
12		Business Development	
13			
14	Vice President	Operations	Stanley E. Wingate 1/
15			
16	Controller	Accounting and	Craig A. Keller
17		Information Systems	
18			
19			
20			
21	1/ David L. Goodin assumed the position of Vice President - Operations effective 01/01/2000		
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CORPORATE STRUCTURE

Year: 1999

Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
Montana-Dakota Utilities Co. (A Division of MDU Resources Group, Inc.)	Utility	$19,165	23.00%
WBI Holdings, Inc.	Pipeline and Energy Services and Oil and Natural Gas Production	37,179	44.63%
Knife River Corporation	Construction Materials and Mining	20,459	24.56%
Utility Services, Inc.	Utility Services	6,505	7.81%
TOTAL		$83,308	100.00%

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

CORPORATE ALLOCATIONS - ELECTRIC

Year: 1999

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$4,733	7.17%	$61,268
Advertising	Customer Service & Information	Directly Assignable	3,493	8.92%	35,664
	Sales	Directly Assignable	5,021	6.87%	68,058
	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	327	0.67%	48,146
Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	9,794	5.67%	163,053
Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,047	6.83%	14,291
Bank Services	Customer Accounts	Directly Assignable	7,486	7.41%	93,574
	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	23,785	7.82%	280,257
Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	3,177	6.15%	48,501
	Steam Power Generation	Actual Costs Incurred	53	23.56%	172
Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	35,419	5.36%	625,721
	Steam Power Generation	Actual Costs Incurred	7,487	23.56%	24,290

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

CORPORATE ALLOCATIONS - ELECTRIC

Year: 1999

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	50,383	8.66%	531,336
	Steam Power Generation	Actual Costs Incurred	23	23.96%	73
Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a Combination of Net Plant Investment and Number of Employees	36,401	6.53%	521,218
Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on Number of Employees	2,961	5.33%	52,606
Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	6,743	6.86%	91,570
Employee Reimbursable Expenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	13,757	5.81%	222,981
Express Mail	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	2	8.70%	21
Freight	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	5	6.58%	71
Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	107,187	10.02%	962,605
	Steam Power Generation	Actual Costs Incurred	4,128	23.56%	13,394

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

CORPORATE ALLOCATIONS - ELECTRIC

Year: 1999

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	86	6.45%	1,247
Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	7,289	5.85%	117,299
Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	10,345	11.98%	75,973
Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	4,145	6.77%	57,113
Moving Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	394	6.53%	5,642
Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience	138,010	10.72%	1,149,311
Printing	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	7,447	6.53%	106,566
Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	636	7.58%	7,759
Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	1,263	6.54%	18,060

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

CORPORATE ALLOCATIONS - ELECTRIC

Year: 1999

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Payroll	Electric Operating	Directly Assignable	1,972	22.60%	6,754
2						
3		Customer Accounts	Directly Assignable	601	8.20%	6,727
4						
5		Customer Service	Directly Assignable	4	8.89%	41
6						
7		Sales	Directly Assignable	59	4.93%	1,138
8						
9		Administrative & General	Various Corporate Overhead Allocation Factors, Time	413,761	6.15%	6,309,463
10			Studies, and/or Actual Costs Incurred			
11						
12		Steam Power Generation	Actual Costs Incurred	808	23.56%	2,621
13						
14	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or	650	9.63%	6,099
15			Actual Costs Incurred			
16						
17	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or	5,909	6.57%	84,007
18			Actual Costs Incurred			
19						
20	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time	5,009	6.56%	71,309
21	Registrations		Studies, and/or Actual Costs Incurred			
22						
23	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,625	6.53%	37,562
24			Studies, and/or Actual Costs Incurred			
25						
26	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors and/or	2,611	6.53%	37,359
27			Actual Costs Incurred			
28						
29						
30	**TOTAL**			$927,036	7.19%	$11,960,920

Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 1999

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				
2		Advertising	Actual Costs Incurred	$2,331		$454
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25		Total USI Operating Revenues for the Year 1999			$99,917,020	
26						
27						
28						
29	**TOTAL**	**Grand Total Affiliate Transactions**		$2,331	0.0023%	$454

Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 1999

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**	Coal Purchases	Actual Costs Incurred			
2		Heskett Station		$5,334,413		$1,435,423
3		Lewis & Clark		2,161,509		581,635
4		Coyote Station		6,530,699 1/		1,757,329
5						
6		Expense	Actual Costs Incurred			
7		Air Service		852		187
8		Reimbursable Expense		48		10
9		Employee Benefits		8		2
10		Reference Material		327		72
11						
12		Capital				
13		Reimbursable Expense	Actual Costs Incurred	1,107		
14						
15		Auto Clearing				
16		Reimbursable Expense	Actual Costs Incurred	1,283		
17						
18						
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20						
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24						
25						
26						
27						
28		Total Knife River Corporation Operating Revenues for the Year 1999			$469,905,204	
29						
30						
31						
32	**TOTAL**	**Grand Total Affiliate Transactions**		$14,030,246	2.9858%	$3,774,658

1/ Reflects Montana-Dakota's share only.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - ELECTRIC

Year: 1999

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**WBI HOLDINGS, INC.**	Expense	Actual Costs Incurred			
2		Contract Services		$11,206		$3,202
3		Meals & Entertainment		29		6
4		Reimbursable Expenses		1,134		251
5		Employee Benefits		72		72
6						
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28		Total WBI Operating Revenues for the Year 1999			$446,218,985	
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30						
31						
32	**TOTAL**	**Grand Total Affiliate Transactions**		$12,441	0.0028%	$3,531

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$15,253		
4		Advertising	Costs Incurred	22,544		
5		Air Service		47,328		
6		Automobile		1,008		
7		Bank Services		67,854		
8		Corporate Aircraft		12,073		
9		Consultant Fees		138,413		
10		Contract Services		118,522		
11		Directors Expenses		148,631		
12		Employee Benefits		15,154		
13		Employee Meeting		22,332		
14		Employee Reimbursable Expense		61,018		
15		Express Mail		6		
16		Freight		18		
17		Legal Retainers & Fees		270,501		
18		Moving Allowance		1,612		
20		Meal Allowance		349		
21		Cash Donations		8,057		
22		Meal & Entertainment		24,704		
23		Industry Dues & Licenses		15,417		
24		Office Expenses		15,238		
25		Supplemental Insurance		291,386		
26		Permits & Filing Fees		1,862		
27		Postage		5,125		
28		Payroll		1,461,712		
29		Printing		30,442		
30		Reference Materials		23,457		
31		Rental		227		
32		Seminars & Meeting Registrations		19,704		
33		Software Maintenance		10,730		
34		Training		10,672		
35		**Total MDU Resources Group, Inc.**		$2,861,349	0.6630%	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Automobile	Factors, Cost of Service Factors, Time	$1		
4		Air Service	Studies and /or Actual Costs Incurred	38		
5		Contract Services		5		
6		Corporate Aircraft		2		
7		Employee Reimbursable Expense		80		
8		Materials		243		
9		Meals & Entertainment		15		
10		Industry Dues & Licenses		22		
11		Office Expenses		307		
12		Office Telephone		54,213		
13		Payroll		8,214		
14		Reference Material		41		
15		Seminars & Meeting Registrations		402		
16						
17		Office Services	* General Office Complex and Office			
18		Automobile	Supplies cost of Service Allocation	22		
19		Contract Services	Factors	1,143		
20		Employee Meetings		10		
21		Express Mail		4,619		
22		Office Expenses		4,192		
23		Postage		5,064		
24		Cost of Service - General Office Buildings		338,030		$82,834
25						
26		Information Systems	* Various Corporate Overhead Allocation			
27		Automobile	Factors and /or Actual Costs Incurred	68		
28		Air Service		67		
29		Contract Services		454		
30		Consultant Fees		6		
31		Corporate Aircraft		25		
32		Employee Reimbursable Expense		78		
33		Meals & Entertainment		11		
34		Office Expenses		4,515		
35		Office Telephone		3,454		

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

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	Payroll		3,007		
2		Reference Material		8		
3		Seminars & Meeting Registrations		270		
4		Software Maintenance		2,552		
5						
6						
7		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
8		Automobile	Factors and /or Actual Costs Incurred	(4)		
9		Corporate Aircraft		98		
10		Employee Benefits		2,069		
11		Meals & Entertainment		19		
12		Office Expenses				
13		Industry Dues & Licenses		76		
14		Payroll		13,376		
15		Reference Material		48		
16		Training Material				
17						
18		Other Direct Charges	Actual Costs Incurred			
19		Utility Discounts		70,104		7,790
20		Corporate/Commercial Air Service		12,810		
21		Contract Services		142,714		
22		Rubber Glove Testing		4,232		
23		Electric Consumption		1,744,110		114,745
24		Gas Consumption		2,229		
25		Telephone		16,730		
26		Miscellaneous		17,503		
27						
28						
29						
30						
31						
32		**Total Montana-Dakota Utilities Co.**		$2,457,292	0.5694%	$205,369

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

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		Insurance		$88,595		
3		Federal & State Tax Liability Payments		7,266,330		
4		KESOP carrying costs		642,934		
5		Tax Deferred Savings Plan		35,449		
6		Interest		(29,170)		
7		Miscellaneous Reimbursements		9,392		
8						
9		**Total Other Transactions/Reimbursements**		$8,013,530	1.8569%	
10						
11		**Grand Total Affiliate Transactions**		$13,332,171	3.0893%	$205,369
12						
13						
14						
15		**Total Knife River Corporation Operating Expenses for 1999**			$431,558,916	

* 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 of 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: 1999

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$13,251		
4		Advertising	Costs Incurred	21,362		
5		Air Service		41,965		
6		Automobile		4,620		
7		Bank Services		64,296		
8		Corporate Aircraft		11,813		
9		Consultant Fees		178,108		
10		Contract Services		110,516		
11		Directors Expenses		141,668		
12		Employee Benefits		13,455		
13		Employee Meeting		25,743		
14		Employee Reimbursable Expense		63,531		
15		Express Mail		6		
16		Freight		20		
17		Legal Retainers & Fees		250,102		
18		Moving Allowance		1,527		
19		Meal Allowance		355		
20		Cash Donations		8,552		
21		Meal & Entertainment		32,530		
22		Industry Dues & Licenses		20,731		
23		Office Expenses		15,815		
24		Supplemental Insurance		276,108		
25		Permits & Filing Fees		2,125		
26		Postage		4,892		
27		Payroll		1,726,654		
28		Printing		28,845		
29		Reference Materials		22,887		
30		Rental		1,899		
31		Seminars & Meeting Registrations		19,422		
32		Software Maintenance		10,167		
33		Training Material		10,112		
34		**Total MDU Resources Group, Inc.**		$3,123,077	0.8246%	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Expense	Factors, Cost of Service Factors, Time			
4		Automobile	Studies and /or Actual Costs Incurred	$2,203		
5		Air Service		75		
6		Annual Easements		1,642		
7		Contract Services		4,464		
8		Custodial Services		353		
9		Corporate Aircraft		15		
10		Employee Reimbursable Expense		713		
11		Freight		13		
12		Materials		3,513		
13		Meals & Entertainment		428		
14		Industry Dues & Licenses		30		
15		Office Expenses		450		
16		Office Telephone		75,095		
17		Payroll		49,323		
18		Permits & Filing Fees		334		
19		Photocopier		316		
20		Reference Material		123		
21		Seminars & Meeting Registrations		1,521		
22		Utilities		2,703		
23						
24		Office Services	* General Office Complex and Office			
25		Expense	Supplies cost of Service Allocation			
26		Automobile	Factors	40		
27		Contract Services		2,031		
28		Employee Meetings		19		
29		Express Mail		4,377		
30		Office Expenses		21,212		
31		Postage		6,209		
32		Cost of Service - General Office Buildings		537,117		$131,620
33						
34		Purchasing Department	* Various Corporate Overhead Allocation			
35		Capital	Factors, Cost of Service Factors, Time			
36		Payroll	Studies and /or Actual Costs Incurred	23,999		

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

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.	Information Systems	* Various Corporate Overhead Allocation			
2		Expense	Factors and /or Actual Costs Incurred			
3		Automobile		83		
4		Air Service		128		
5		Contract Services		5,449		
6		Consultant Fees		76		
7		Corporate Aircraft		51		
8		Industry Dues & Licenses		2		
9		Employee Benefits		6		
10		Employee Reimbursable Expense		266		
11		Meals & Entertainment		21		
12		Office Expenses		55,171		
13		Office Telephone		8,168		
14		Payroll		11,452		
15		Reference Material		52		
16		Seminars & Meeting Registrations		342		
17		Software Maintenance		2,418		
18						
19		Region Operations	Actual Costs Incurred			
20		Expense				
21		Automobile		2,967		
22		Contract Services		6		
23		Freight		3		
24		Materials		107		
25		OfficeTelephone		62		
26		Payroll		10,693		
27		Utilities		272		

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

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.	Transportation Department	* Various Corporate Overhead Allocation			
2		Capital	Factors, Time Studies and /or Actual			
3		Payroll	Costs incurred	11,522		
4		Clearing Accounts				
5		Automobile		2,460		
6		Air Service		243		
7		Contract Services		45		
8		Corporate Aircraft		175		
9		Custodial Services		223		
10		Employee Reimbursable Expense		992		
11		Materials		3,328		
12		Meals & Entertainment		471		
13		Office Expenses		9		
14		Office Telephone		367		
15		Payroll		10,704		
16		Utilities		159		
17						
18		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
19		Expense	Factors, Time Studies and /or Actual			
20		Automobile	Costs incurred	(188)		
21		Annual Easements		16		
22		Corporate Aircraft		144		
23		Employee Benefits		1,053		
24		Industry Dues & Licenses		72		
25		Meals & Entertainment		18		
26		Office Expenses		60		
27		Payroll		19,383		
28		Reference Material		60		
29		Seminars & Meeting Registrations		15		
30		Training Material		10		
31						

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

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.	Capital				
2		Automobile		63		
3		Air Service		811		
4		Corporate Aircraft		391		
5		Employee Reimbursable Expense		1,166		
6		Meals & Entertainment		426		
7		Office Expenses		20		
8		Payroll		1,666		
9		Reference Material		112		
10		Seminars & Meeting Registrations		675		
11						
12		Other Direct Charges	Actual Costs Incurred			
13		Utility/Merchandise Discounts		106,600		64,119
14		Corporate Aircraft		71,266		
15		Contract Services		89,599		
16		Dispatch Services		1,560		
17		Cathodic Protection		13,036		3,989
18		Purchased Power for Compressor Stations		76,441		67,508
19		Electric Compressor - Electricity Cost		96,065		27,459
20		Office Building Utilities		95,223		59,442
21		Telephone		11,067		
22		Miscellaneous		2,938		
23		Nomination Services				
24		Pool Car Usage		16,003		
25						
26		Total Montana-Dakota Utilities Co. 1/		$1,472,582	0.3888%	$354,137
27						
28		1/ Total Montana-Dakota Charges By Category				
29		Expense		$1,412,555	0.3729%	
30		Capital		40,851	0.0108%	
31		Clearing		19,176	0.0051%	
32		Total		$1,472,582	0.3888%	
33						

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

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	$84,981		
3		Federal & State Tax Liability Payments		6,332,767		
4		Dividends on Preferred Stock of WBI		396,000		$95,744
5		Tax Deferred Savings Plan		28,962		
6		KESOP carrying costs		610,771		
7		Interest		(27,640)		
8		Miscellaneous Reimbursements		23,424		
9						
10		**Total Other Transactions/Reimbursements**		$7,449,265	1.9668%	$95,744
11						
12		**Grand Total Affiliate Transactions**		$12,044,924	3.1802%	$449,881
13						
14						
15						
16		**Total WBI Holdings Operating Expenses for 1999**			$378,747,370	

* 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 of 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: 1999

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.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$428		
4		Advertising	Costs Incurred	591		
5		Air Service		6,440		
6		Automobile		34		
7		Bank Services		1,779		
8		Corporate Aircraft		369		
9		Consultant Fees		4,158		
10		Contract Services		4,685		
11		Directors Expenses		3,905		
12		Employee Benefits		1,378		
13		Employee Meeting		1,408		
14		Employee Reimbursable Expense		4,314		
15		Legal Retainers & Fees		7,306		
16		Moving Allowance		42		
17		Meal Allowance		9		
18		Cash Donations		203		
19		Meal & Entertainment		1,500		
20		Industry Dues & Licenses		411		
21		Office Expenses		413		
22		Supplemental Insurance		7,639		
23		Permits & Filing Fees		108		
24		Postage		134		
25		Payroll		43,814		
26		Printing		798		
27		Reference Materials		616		
28		Seminars & Meeting Registrations		523		
29		Software Maintenance		281		
30		Training Material		280		
31		**Total MDU Resources Group, Inc.**		$93,566	0.1058%	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

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.	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Materials	Factors, Cost of Service Factors, Time	$2		
4		Office Expenses	Studies and /or Actual Costs Incurred	9		
5		Office Telephone		455		
6		Payroll		69		
7		Seminars & Meeting Registrations		3		
8						
9		Office Services	* General Office Complex and Office			
10		Contract Services	Supplies Cost of Service Allocation	36		
11		Express Mail	Factors	127		
12		Office Expenses		996		
13		Postage		133		
14		Cost of Service - General Office Buildings		76,243		$18,683
15						
16		Information Systems	* Various Corporate Overhead Allocation			
17		Automobile	Factors and /or Actual Costs Incurred	2		
18		Air Service		2		
19		Contract Services		266		
20		Corporate Aircraft		1		
21		Employee Reimbursable Expense		1,704		
22		Meals & Entertainment		132		
23		Office Expenses		2,354		
24		Office Telephone		78		
25		Payroll		54		
26		Reference Material		2		
27		Seminars & Meeting Registrations		7		
28		Software Maintenance		3,066		

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

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.	Marketing	* Various Corporate Overhead Allocation			
2		Air Service	Factors, Time Studies and/or	5,878		
3		Employee Reimbursable Expense	Actual Costs Incurred	2,638		
4		Meals & Entertainment		870		
5						
6						
7						
8		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
9		Automobile	Factors, Time Studies and/or	(1)		
10		Air Service	Actual Costs Incurred	3,065		
11		Corporate Aircraft		2,072		
12		Cash Donations		10,018		
13		Employee Benefits		74		
14		Industry Dues & Licenses		2		
15		Meals & Entertainment		143		
16		Employee Reimbursable Expense		1,517		
17		Payroll		401		
18		Permits & Filing Fees		51		
19		Training Material		603		
20						
21		Other Direct Charges	Actual Costs Incurred			
22		Legal Fees		251,258		
23		Contract Services		24,605		
24		Air Service		18,292		
25		Permits & Filing Fees		45,000		
26		Miscellaneous		16,396		
27						
28						
29						
30						
31						
32		**Total Montana-Dakota Utilities Co.**		$468,623	0.5301%	$18,683

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 1999

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 TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
2		Federal & State Tax Liability Payments		$4,101,678		
3		KESOP carrying costs		16,746		
4						
5		**Total Other Transactions/Reimbursements**		$4,118,424	4.6589%	
6						
7		**Grand Total Affiliate Transactions**		$4,680,613	5.2949%	$18,683
8						
9						
10						
11		**Total Utility Services Inc Operating Expenses for 1999**			$88,399,288	

* 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 of 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.

MONTANA UTILITY INCOME STATEMENT

Year: 1999

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	$32,730,515	$34,747,713	6.16%
2					
3		Operating Expenses			
4	401	Operation Expenses	$17,470,947	$18,133,801	3.79%
5	402	Maintenance Expense	1,988,817	2,137,358	7.47%
6	403	Depreciation Expense	4,410,570	4,405,628	-0.11%
7	404-405	Amortization of Electric Plant	154,363	160,816	4.18%
8	406	Amort. of Plant Acquisition Adjustments	99,652	97,605	-2.05%
9	407	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	2,345,159	2,528,678	7.83%
12	409.1	Income Taxes - Federal	1,942,040	2,026,815	4.37%
13		- Other	418,818	401,574	-4.12%
14	410.1	Provision for Deferred Income Taxes	(365,475)	(230,953)	36.81%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(237,053)	(36,188)	84.73%
16	411.4	Investment Tax Credit Adjustments			
17	411.6	(Less) Gains from Disposition of Utility Plant			
18	411.7	Losses from Disposition of Utility Plant			
19					
20		**TOTAL Utility Operating Expenses**	$28,227,838	$29,625,134	4.95%
21		**NET UTILITY OPERATING INCOME**	$4,502,677	$5,122,579	13.77%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	$10,502,131	$10,210,220	-2.78%
3	442	Commercial & Industrial - Small	6,043,309	5,851,206	-3.18%
4		Commercial & Industrial - Large	11,004,984	11,458,498	4.12%
5	444	Public Street & Highway Lighting	672,513	674,014	0.22%
6	445	Other Sales to Public Authorities	324,447	318,833	-1.73%
7	446	Sales to Railroads & Railways			
8	448	Interdepartmental Sales			
9		Net Unbilled Revenue	(33,080)	(81,039)	-144.98%
10		**TOTAL Sales to Ultimate Consumers**	$28,514,304	$28,431,732	-0.29%
11	447	Sales for Resale	3,182,031	5,375,379	68.93%
12					
13		**TOTAL Sales of Electricity**	$31,696,335	$33,807,111	6.66%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	$31,696,335	$33,807,111	6.66%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues			
19	451	Miscellaneous Service Revenues	$12,358	$9,476	-23.32%
20	453	Sales of Water & Water Power			
21	454	Rent From Electric Property	764,608	785,611	2.75%
22	455	Interdepartmental Rents			
23	456	Other Electric Revenues	257,214	145,515	-43.43%
24					
25		**TOTAL Other Operating Revenues**	$1,034,180	$940,602	-9.05%
26		**Total Electric Operating Revenues**	$32,730,515	$34,747,713	6.16%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 1999

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	$280,644	$293,376	4.54%
6	501 Fuel	6,406,692	6,714,227	4.80%
7	502 Steam Expenses	604,895	643,419	6.37%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	214,834	235,770	9.75%
11	506 Miscellaneous Steam Power Expenses	330,467	359,482	8.78%
12	507 Rents			
13				
14	TOTAL Operation - Steam	7,837,532	8,246,274	5.22%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	103,304	105,923	2.54%
18	511 Maintenance of Structures	72,172	77,164	6.92%
19	512 Maintenance of Boiler Plant	505,767	622,158	23.01%
20	513 Maintenance of Electric Plant	125,741	77,240	-38.57%
21	514 Maintenance of Miscellaneous Steam Plant	139,822	122,472	-12.41%
22				
23	TOTAL Maintenance - Steam	946,806	1,004,957	6.14%
24				
25	**TOTAL Steam Power Production Expenses**	$8,784,338	$9,251,231	5.32%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources		NOT	
34	522 (Less) Steam Transferred - Cr.		APPLICABLE	
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment		NOT	
45	531 Maintenance of Electric Plant		APPLICABLE	
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 1999

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	Hydraulic Power Generation			
3	Operation			
4	535 Operation Supervision & Engineering			
5	536 Water for Power			
6	537 Hydraulic Expenses		NOT	
7	538 Electric Expenses		APPLICABLE	
8	539 Miscellaneous Hydraulic Power Gen. Expenses			
9	540 Rents			
10				
11	TOTAL Operation - Hydraulic			
12				
13	Maintenance			
14	541 Maintenance Supervision & Engineering			
15	542 Maintenance of Structures		NOT	
16	543 Maint. of Reservoirs, Dams & Waterways		APPLICABLE	
17	544 Maintenance of Electric Plant			
18	545 Maintenance of Miscellaneous Hydro Plant			
19				
20	TOTAL Maintenance - Hydraulic			
21				
22	**TOTAL Hydraulic Power Production Expenses**			
23				
24	Other Power Generation			
25	Operation			
26	546 Operation Supervision & Engineering	$10,080	$8,322	-17.44%
27	547 Fuel	212,149	190,971	-9.98%
28	548 Generation Expenses	1,233	1,075	-12.81%
29	549 Miscellaneous Other Power Gen. Expenses	9,965	8,281	-16.90%
30	550 Rents			
31				
32	TOTAL Operation - Other	233,427	208,649	-10.61%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	5,895	3,680	-37.57%
36	552 Maintenance of Structures	3,259	1,632	-49.92%
37	553 Maintenance of Generating & Electric Plant	17,592	11,759	-33.16%
38	554 Maintenance of Misc. Other Power Gen. Plant	2,713	1,463	-46.07%
39				
40	TOTAL Maintenance - Other	29,459	18,534	-37.09%
41				
42	**TOTAL Other Power Production Expenses**	$262,886	$227,183	-13.58%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	$4,128,902	$4,341,780	5.16%
46	556 System Control & Load Dispatching	146,474	162,713	11.09%
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	$4,275,376	$4,504,493	5.36%
50				
51	**TOTAL Power Production Expenses**	$13,322,600	$13,982,907	4.96%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 1999

	Account Number & Title	Last Year	This Year	% Change
1	Transmission Expenses			
2	Operation			
3	560 Operation Supervision & Engineering	$162,362	$183,217	12.84%
4	561 Load Dispatching	60,398	54,159	-10.33%
5	562 Station Expenses	106,340	112,739	6.02%
6	563 Overhead Line Expenses	29,454	28,172	-4.35%
7	564 Underground Line Expenses			
8	565 Transmission of Electricity by Others	87,814	89,182	1.56%
9	566 Miscellaneous Transmission Expenses	18,565	16,200	-12.74%
10	567 Rents	193,797	198,945	2.66%
11				
12	TOTAL Operation - Transmission	658,730	682,614	3.63%
13	Maintenance			
14	568 Maintenance Supervision & Engineering	37,023	30,858	-16.65%
15	569 Maintenance of Structures			
16	570 Maintenance of Station Equipment	102,112	110,493	8.21%
17	571 Maintenance of Overhead Lines	100,319	115,602	15.23%
18	572 Maintenance of Underground Lines			
19	573 Maintenance of Misc. Transmission Plant	159	(361)	-327.04%
20				
21	TOTAL Maintenance - Transmission	239,613	256,592	7.09%
22				
23	**TOTAL Transmission Expenses**	$898,343	$939,206	4.55%
24				
25	Distribution Expenses			
26	Operation			
27	580 Operation Supervision & Engineering	$203,903	$160,099	-21.48%
28	581 Load Dispatching			
29	582 Station Expenses	34,095	49,124	44.08%
30	583 Overhead Line Expenses	147,480	68,520	-53.54%
31	584 Underground Line Expenses	103,714	109,961	6.02%
32	585 Street Lighting & Signal System Expenses	5,998	13,825	130.49%
33	586 Meter Expenses	121,386	158,569	30.63%
34	587 Customer Installations Expenses	61,524	71,295	15.88%
35	588 Miscellaneous Distribution Expenses	236,097	279,135	18.23%
36	589 Rents	19,106	17,701	-7.35%
37				
38	TOTAL Operation - Distribution	933,303	928,229	-0.54%
39	Maintenance			
40	590 Maintenance Supervision & Engineering	107,207	111,869	4.35%
41	591 Maintenance of Structures			
42	592 Maintenance of Station Equipment	24,626	29,705	20.62%
43	593 Maintenance of Overhead Lines	318,097	386,431	21.48%
44	594 Maintenance of Underground Lines	112,279	102,680	-8.55%
45	595 Maintenance of Line Transformers	34,070	21,458	-37.02%
46	596 Maintenance of Street Lighting, Signal Systems	31,719	33,572	5.84%
47	597 Maintenance of Meters	3,392	4,087	20.49%
48	598 Maintenance of Miscellaneous Dist. Plant	28,254	33,327	17.95%
49				
50	TOTAL Maintenance - Distribution	659,644	723,129	9.62%
51				
52	**TOTAL Distribution Expenses**	$1,592,947	$1,651,358	3.67%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 1999

	Account Number & Title		Last Year	This Year	% Change
1		Customer Accounts Expenses			
2	Operation				
3	901	Supervision	$45,471	$55,649	22.38%
4	902	Meter Reading Expenses	153,219	157,288	2.66%
5	903	Customer Records & Collection Expenses	411,888	493,679	19.86%
6	904	Uncollectible Accounts Expenses	33,666	36,993	9.88%
7	905	Miscellaneous Customer Accounts Expenses	44,209	38,464	-13.00%
8					
9		TOTAL Customer Accounts Expenses	$688,453	$782,073	13.60%
10					
11		Customer Service & Information Expenses			
12	Operation				
13	907	Supervision	$163	$2,777	1603.68%
14	908	Customer Assistance Expenses	17,600	18,983	7.86%
15	909	Informational & Instructional Adv. Expenses	11,157	5,060	-54.65%
16	910	Miscellaneous Customer Service & Info. Exp.		(23)	-100.00%
17					
18		TOTAL Customer Service & Info Expenses	$28,920	$26,797	-7.34%
19					
20		Sales Expenses			
21	Operation				
22	911	Supervision	$38,560	$41,875	8.60%
23	912	Demonstrating & Selling Expenses	26,441	28,570	8.05%
24	913	Advertising Expenses	7,533	10,888	44.54%
25	916	Miscellaneous Sales Expenses	7,746	8,613	11.19%
26					
27		TOTAL Sales Expenses	$80,280	$89,946	12.04%
28					
29		Administrative & General Expenses			
30	Operation				
31	920	Administrative & General Salaries	$887,616	$902,526	1.68%
32	921	Office Supplies & Expenses	394,485	462,005	17.12%
33	922	(Less) Administrative Expenses Transferred - Cr.			
34	923	Outside Services Employed	124,561	185,261	48.73%
35	924	Property Insurance	44,093	43,859	-0.53%
36	925	Injuries & Damages	133,885	138,477	3.43%
37	926	Employee Pensions & Benefits	933,709	711,598	-23.79%
38	927	Franchise Requirements			
39	928	Regulatory Commission Expenses	14,163	19,004	34.18%
40	929	(Less) Duplicate Charges - Cr.			
41	930.1	General Advertising Expenses	3,846	3,687	-4.13%
42	930.2	Miscellaneous General Expenses	192,690	191,110	-0.82%
43	931	Rents	5,878	7,199	22.47%
44					
45		TOTAL Operation - Admin. & General	2,734,926	2,664,726	-2.57%
46	Maintenance				
47	935	Maintenance of General Plant	113,295	134,146	18.40%
48					
49		**TOTAL Administrative & General Expenses**	$2,848,221	$2,798,872	-1.73%
50					
51		**TOTAL Operation & Maintenance Expenses**	$19,459,764	$20,271,159	4.17%

MONTANA TAXES OTHER THAN INCOME

Year: 1999

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$328,210	$310,797	-5.31%
2	Secretary of State	258	6,047	2243.80%
3	Montana Consumer Counsel	22,060	26,658	20.84%
4	Montana PSC	69,085	69,894	1.17%
5	Montana Electric	16,756	13,071	-21.99%
6	Coal Conversion	81,832	87,294	6.67%
7	Delaware Franchise	20,797	21,019	1.07%
8	Property Taxes	1,806,161	1,993,898	10.39%
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50	**TOTAL MT Taxes Other Than Income**	$2,345,159	$2,528,678	7.83%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC Year: 1999

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	A&D Constructors, Inc.	Construction Services	$84,691	$19,954	23.56%
2					
3	API Construction Company	Construction Services	227,928	53,703	23.56%
4					
5	Arthur Andersen LLP	Audit Service	137,500	12,730	9.26%
6					
7	Beacon Consulting, Inc.	Consultant - CIS System	165,360	24,163	14.61%
8					
9	Bull HN Information Systems	Contract Services - Software Maintenance	220,006	23,174	10.53%
10					
11	Bullinger Tree Service	Tree Trimming Service	196,703	68	0.03%
12					
13	Chief Construction	Construction Services	417,552	247	0.06%
14					
15	Christensen & Associates	Consultant - Investor Relations	76,126	4,972	6.53%
16					
17	Customerlink	Telemarketing Service	103,162	0	0.00%
18					
19	Daksoft, Inc.	Consultant - CIS System	210,297	30,105	14.32%
20					
21	Friendly Advanced	Consultant - CIS System	210,595	30,772	14.61%
22					
23	Gagnon, Inc.	Construction Services	76,461	18,015	23.56%
24					
25	GE Power Generation Service	Construction Services	411,424	96,937	23.56%
26					
27	Hamilton Spray	Contract Services - Pole Treatment	206,296	46,266	22.43%
28					
29	Harris Group, Inc.	Construction Services	95,917	22,599	23.56%
30					
31	Hedahl's of Bismarck	Contract Services - Auto and Work Equip.	144,811	1,160	0.80%
32					
33	Horsley Specialties	Construction Services - Asbestos Remova	191,240	2,321	1.21%
34					
35	Howden Fan Company	Construction Services	307,047	72,345	23.56%
36					
37	Industrial Contractors, Inc.	Construction Services	1,476,875	347,973	23.56%
38					
39	Itec Enterprises, Inc.	Construction Services	116,346	0	0.00%
40					
41	James W. Sewall Company	Consultant - GEMS	81,874	11,964	14.61%
42					
43	J.D. Edwards	Contract Services - Software Maintenance	151,530	20,625	13.61%
44					
45	Jim's Water Service, Inc.	Construction Services	90,311	0	0.00%
46					
47	Leboeuf, Lamb, Greene & MacRae LLP	Legal Services	91,233	5,958	6.53%
48					
49	Lehman Brothers	Consultant - Financial	206,408	28,078	13.60%
50					
51	Mappcor	Organization	213,750	56,895	26.62%
52					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - ELECTRIC

Year: 1999

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	New York Life	K-Plan Administrator	171,073	429	0.25%
2					
3	Norwest Bank	Stock Transfer Agent	302,065	16,125	5.34%
4					
5	Olsten Staffing Services, Inc.	Contract Services	78,110	109	0.14%
6					
7	One Call Locators, Inc.	Line Location Service	552,841	25,923	4.69%
8					
9	Osmose Wood	Contract Services - Pole Treatment	164,946	28,300	17.16%
10					
11	Power Generation Service	Construction Services	699,809	164,885	23.56%
12					
13	Prime Power & Communicatio	Construction Services	308,991	0	0.00%
14					
15	Progressive Maintenance	Contract Services - Custodial	117,553	17,352	14.76%
16					
17	Richard A. Riley	Consultant - CIS System	85,917	12,554	14.61%
18					
19	Skeels Electric Company	Contract Services - Electrical	88,376	12,116	13.71%
20					
21	Southern Cross Corporation	Contract Services - Leak Detection	184,911	0	0.00%
22					
23	State-Line Contractors, Inc.	Contruction Services	99,216	28,146	28.37%
24					
25	Sterling Software	Consultant - CIS System	348,927	50,116	14.36%
26					
27	Strategic Capital, Inc.	Consultant - Financial	106,773	6,948	6.51%
28					
29	Swanson & Youngdale, Inc.	Contract Services	110,663	26,074	23.56%
30					
31	Thelen, Reid, & Priest LLP	Legal Services	1,062,951	56,526	5.32%
32					
33	Towers Perrin	Consultant - Compensation and Benefits	283,359	23,505	8.30%
34					
35	US Bank	Bank Services	103,592	7,760	7.49%
36					
37	Utilities International	Consultant - Financial	239,668	33,095	13.81%
38					
39	Utility Partners, LC	Consultant - Mobile Service Computer	982,859	143,617	14.61%
40					
41	Viking Travel	Travel Agency	123,554	9,456	7.65%
42					
43	Wang Laboratories, Inc.	Contract Services - Computer System	108,530	11,658	10.74%
44	**TOTAL Payments for Services**		$12,236,127	$1,605,718	13.12%

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 1999

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$4,249	$200	4.71%
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49				
50	**TOTAL Contributions**	$4,249	$200	4.71%

Pension Costs

Year: 1999

	Item	Current Year	Last Year	% Change
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				
6	**Change in Benefit Obligation**	(000's)	(000's)	
7	Benefit obligation at beginning of year	$134,762	$126,985	6.12%
8	Service cost	2,993	3,055	-2.03%
9	Interest Cost	9,032	8,838	2.20%
10	Plan participants' contributions	-	-	0.00%
11	Amendments	2,072	-	N/A
12	Actuarial (Gain) Loss	(11,105)	4,111	-370.13%
13	Acquisition	-	-	0.00%
14	Benefits paid	(8,364)	(8,227)	-1.67%
15	Benefit obligation at end of year	$129,390	$134,762	-3.99%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$186,156	$164,330	13.28%
18	Actual return on plan assets	27,788	30,053	-7.54%
19	Acquisition	-	-	0.00%
20	Employer contribution	-	-	0.00%
21	Plan participants' contributions	-	-	0.00%
22	Benefits paid	(8,364)	(8,227)	-1.67%
23	Fair value of plan assets at end of year	$205,580	$186,156	10.43%
24	**Funded Status**	$76,190	$51,394	48.25%
25	Unrecognized net actuarial loss	(83,146)	(57,917)	-43.56%
26	Unrecognized prior service cost	6,865	5,398	27.18%
27	Unrecognized net transition obligation	(3,571)	(4,423)	19.26%
28	Accrued benefit cost	($3,662)	($5,548)	33.99%
29				
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	7.75	6.75	14.81%
32	Expected return on plan assets	8.50	8.50	0.00%
33	Rate of compensation increase	5.00	4.50	11.11%
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost	$2,993	$3,055	-2.03%
37	Interest cost	9,032	8,838	2.20%
38	Expected return on plan assets	(12,909)	(11,637)	-10.93%
39	Amortization of prior service cost	604	604	0.00%
40	Recognized net actuarial gain	(754)	(390)	-93.33%
41	Transition amount amortization	(852)	(852)	0.00%
42	Net periodic benefit cost	($1,886)	($382)	-393.72%
43				
44	**Montana Intrastate Costs:**			
45	Pension Costs	($1,886)	($382)	-393.72%
46	Pension Costs Capitalized	(185)	(4)	-4525.00%
47	Accumulated Pension Asset (Liability) at Year End	(3,662)	(5,548)	33.99%
48	**Number of Company Employees:**			
49	Covered by the Plan	1,997	1,974	1.17%
50	Not Covered by the Plan	16	13	23.08%
51	Active	1,047	1,140	-8.16%
52	Retired	844	801	5.37%
53	Deferred Vested Terminated	106	33	221.21%

Other Post Employment Benefits (OPEBS)

Year: 1999

	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	7.75	6.75	14.81%
8	Expected return on plan assets	7.50	7.50	0.00%
9	Medical Cost Inflation Rate	6.00	7.00	-14.29%
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	
11	Rate of compensation increase	5.00	4.50	11.11%
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	$49,085	$52,366	-6.27%
19	Service cost	902	984	-8.33%
20	Interest Cost	3,300	3,444	-4.18%
21	Plan participants' contributions	518	413	25.42%
22	Amendments	3,194	(4,137)	177.21%
23	Actuarial Gain	(8,414)	(1,120)	-651.25%
24	Acquisition	-	-	0.00%
25	Benefits paid	(2,832)	(2,865)	1.15%
26	Benefit obligation at end of year	$45,753	$49,085	-6.79%
27	**Change in Plan Assets**			
28	Fair value of plan assets at beginning of year	$30,803	$23,870	29.04%
29	Actual return on plan assets	4,037	4,859	-16.92%
30	Acquisition	-	-	0.00%
31	Employer contribution	3,745	4,526	-17.26%
32	Plan participants' contributions	518	413	25.42%
33	Benefits paid	(2,832)	(2,865)	1.15%
34	Fair value of plan assets at end of year	$36,271	$30,803	17.75%
35	**Funded Status**	($9,482)	($18,282)	48.13%
36	Unrecognized net actuarial loss	(16,255)	(6,099)	-166.52%
37	Unrecognized prior service cost	-	(1,233)	100.00%
38	Unrecognized transition obligation	24,623	24,500	0.50%
39	Accrued benefit cost	($1,114)	($1,114)	0.00%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	$902	$984	-8.33%
42	Interest cost	3,300	3,444	-4.18%
43	Expected return on plan assets	(2,206)	(1,861)	-18.54%
44	Amortization of prior service cost	-	-	0.00%
45	Recognized net acturial gain	(90)	-	N/A
46	Transition amount amortization	1,838	1,957	-6.08%
47	Net periodic benefit cost	$3,744	$4,524	-17.24%
48	**Accumulated Post Retirement Benefit Obligation**			
49	Amount Funded through VEBA	$4,263	$4,939	-13.69%
50	Amount Funded through 401(h)			
51	Amount Funded through Other ________________			
52	TOTAL	$4,263	$4,939	-13.69%
53	Amount that was tax deductible - VEBA	$2,744 1/	$3,765	-27.12%
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other ___________			
56	TOTAL	$2,744	$3,765	-27.12%

1/ Estimated.

Other Post Employment Benefits (OPEBS) Continued

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	1,787	1,898	-5.85%
3	Not Covered by the Plan	16	13	23.08%
4	Active	995	1,106	-10.04%
5	Retired	590	592	-0.34%
6	Spouses/Dependants covered by the Plan	202	200	1.00%
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							
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PROPRIETARY SCHEDULE

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.	$323,077	$203,960	$233,935	$760,972	$620,607	23%
2	Douglas C. Kane - Executive Vice President Chief Administrative & Corporate Development Officer	210,220	79,146	119,632	408,998	534,111	-23%
3	Ronald D. Tipton - President & C.E.O. of Montana-Dakota Utilities Co.	235,508	70,327	119,395	425,230	523,941	-19%
4	Warren L. Robinson - Executive Vice President, Treasurer & Chief Financial Officer	172,396	86,591	96,497	355,484	370,287	-4%
5	Lester H. Loble, II - Vice President, Secretary & General Counsel	150,750	55,355	78,983	285,088	310,249	-8%

1/ See page 19a 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, 1999, 1998, and 1997, for those persons who (i) served as the Chief Executive Officer during 1999, and (ii) were the other four most highly compensated executive officers of the Company at December 31, 1999 (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 compensation(3) ($)	Restricted stock awards ($)	Securities underlying Options/SARs (#)	LTIP payouts ($)	All other compensation(8) ($)
Martin A. White	1999	323,077	203,960		229,063(4)	—	—	4,872
—President & C.E.O.	1998	254,808	139,461		54,157(5)	122,760(6)	43,937(7)	5,484
	1997	147,316	54,450		—	—	—	4,875
Douglas C. Kane	1999	210,220	79,146		114,532(4)	—	—	5,100
—Executive Vice President,	1998	210,185	63,032		62,689(5)	55,800(6)	137,605(7)	4,800
Chief Administrative & Corporate Development Officer	1997	201,772	92,250		—	—	—	4,750
Ronald D. Tipton	1999	235,508	70,327		114,532(4)	—	—	4,863
—President & C.E.O. of	1998	223,491	103,500		—	49,125(6)	142,827(7)	4,998
Montana-Dakota Utilities Co.	1997	200,655	92,250		—	—	—	4,948
Warren L. Robinson	1999	172,396	86,591		91,625(4)	—	—	4,872
—Executive Vice President,	1998	150,865	57,855		43,771(5)	37,950(6)	75,320(7)	4,526
Treasurer & Chief Financial Officer	1997	128,843	63,750		—	—	—	3,865
Lester H. Loble, II	1999	150,750	55,355	5,741	68,719(4)	—	—	4,523
—Vice President, Secretary	1998	139,694	43,848	3,963	41,916(5)	27,900(6)	48,737(7)	4,191
and General Counsel	1997	127,473	54,450	3,620	—	—	—	3,824

(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, 1999, the Named Officers held the following amounts of restricted stock: Mr. White—12,190 shares ($243,420); Mr. Kane—7,535 shares ($150,465); Mr. Tipton—7,250 shares ($144,774); Mr. Robinson—5,770 shares ($115,220); and Mr. Loble—4,695 shares ($93,754).

(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 1995-97 performance cycle.

(8) Totals shown are the Company contributions to the Tax Deferred Compensation Savings Plan, with the following exceptions: the total includes insurance premiums of $72 for Mr. White, $300 for Mr. Kane, $72 for Mr. Robinson, and $63 for Mr. Tipton.

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	—	—
Douglas C. Kane	—	—	46,343	55,800	361,946	—
Ronald D. Tipton	—	—	—	49,125	—	—
Warren L. Robinson	7,912	95,521	—	37,950	—	—
Lester H. Loble, II	—	—	14,850	27,900	113,387	—

(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	$ 79,494	$ 88,111	$ 96,729	$105,347	$113,965
150,000	95,611	106,041	116,472	126,902	137,332
175,000	108,466	119,621	130,776	141,931	153,086
200,000	121,066	132,221	143,376	154,531	165,686
225,000	132,046	143,201	154,356	165,511	176,666
250,000	142,966	154,121	165,276	176,431	187,586
300,000	179,206	190,361	201,516	212,671	223,826
350,000	226,786	237,941	249,096	260,251	271,406
400,000	267,766	278,921	290,076	301,231	312,386
450,000	307,666	318,821	329,976	341,131	352,286
500,000	347,866	359,021	370,176	381,331	392,486

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 1999, 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, 1999, the Named Officers were credited with the following years of service under the plans: Mr. White: Pension, 8, SISP, 8; Mr. Kane: Pension, 28, SISP, 18; Mr. Tipton: Pension, 16, SISP, 16; Mr. Robinson: Pension 11, SISP 11; and Mr. Loble: Pension, 12, SISP, 12. 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 28.9% increase in base salary for 1999. This increase took into account Mr. White's personal performance during 1999, his time as chief executive officer, and comparative industry data. Mr. White became chief executive officer in April 1998. During 1999, only approximately 33.6% 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 10.68% for 1999.

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 $203.960 (or 114.7% of the targeted amount) in annual incentive compensation for 1999; the other Named Officers received an average of $72,855, or 97.9% 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. Since options and related dividend equivalents were granted in 1998 and the three-year performance cycle (1998-2000) is still running, the Compensation Committee determined that it was not necessary to grant further options in 1999.

Restricted stock awards were made in 1999 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.

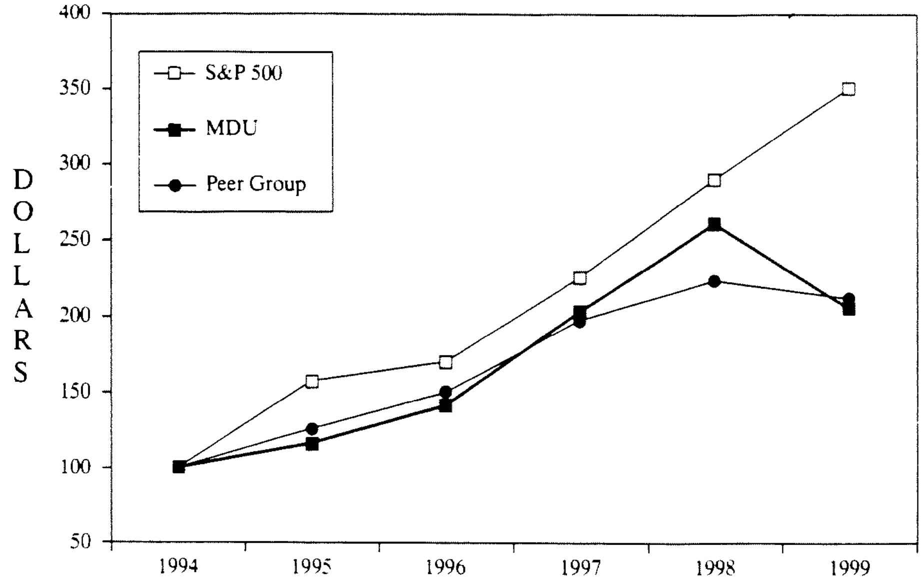
In 1994, the Board of Directors adopted Stock Ownership Guidelines under which executives are required to own Company Common Stock valued from one to four times their annual salary.

The 1999 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. Stockholders are being asked at the 2000 Annual Meeting to approve amendments to the 1992 Key Employee Stock Option Plan and the 1997 Executive Long-Term Incentive Plan to permit deductibility of certain grants under the plans under Section 162(m).

San W. Orr, Jr., Chairman	Harry J. Pearce, Member	Homer A. Scott, Jr., Member

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

Total Stockholder Return Index (1994=100)



	1994	1995	1996	1997	1998	1999
S&P 500	100.00	137.58	169.17	225.60	290.08	351.12
MDU	100.00	116.07	141.09	202.65	260.84	205.78
Peer Group	100.00	125.72	149.42	196.57	223.22	211.84

(1) All data is indexed to December 31, 1994, 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 Black Hills Corporation, Coastal Corporation, Equitable Resources, Inc., LG&E Energy Corp., Minnesota Power, Inc., The Montana Power Company, NorthWestern Corporation, ONEOK, Inc., Otter Tail Power Company, Questar Corporation, and UGI Corporation.

BALANCE SHEET

Year: 1999

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Electric Plant in Service	$517,912,067	$529,514,416	2.24%
4	101.1	Property Under Capital Leases			
5	102	Electric Plant Purchased or Sold			
6	104	Electric Plant Leased to Others			
7	105	Electric Plant Held for Future Use			
8	106	Completed Constr. Not Classified - Electric			
9	107	Construction Work in Progress - Electric	3,616,183	2,386,702	-34.00%
10	108	(Less) Accumulated Depreciation	(274,394,149)	(287,547,986)	4.79%
11	111	(Less) Accumulated Amortization	(430,284)	(731,323)	69.96%
12	114	Electric Plant Acquisition Adjustments	10,387,642	10,387,643	0.00%
13	115	(Less) Accum. Amort. Electric Plant Acq. Adj.	(5,091,998)	(5,506,258)	8.14%
14	120	Nuclear Fuel (Net)			
15		Other Utility Plant	213,887,500	224,598,142	5.01%
16		Accum. Depr. and Amort. - Other Utl. Plant	(113,207,861)	(120,223,427)	6.20%
17		**TOTAL Utility Plant**	$352,679,100	$352,877,909	0.06%
18	**Other Property & Investments**				
19	121	Nonutility Property	$162,463	$161,779	-0.42%
20	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(6,418)	(14,883)	131.89%
21	123	Investments in Associated Companies			
22	123.1	Investments in Subsidiary Companies	424,583,132	538,839,875	26.91%
23	124	Other Investments	28,287,140	27,885,507	-1.42%
24	125	Sinking Funds			
25		**TOTAL Other Property & Investments**	$453,026,317	$566,872,278	25.13%
26	**Current & Accrued Assets**				
27	131	Cash	$6,460,876	$3,453,935	-46.54%
28	132-134	Special Deposits	1,100	1,100	0.00%
29	135	Working Funds	14,705	14,515	-1.29%
30	136	Temporary Cash Investments		5,000,000	
31	141	Notes Receivable			
32	142	Customer Accounts Receivable	19,267,843	25,223,733	30.91%
33	143	Other Accounts Receivable	2,223,002	2,610,933	17.45%
34	144	(Less) Accum. Provision for Uncollectible Accts.	(142,462)	(189,276)	32.86%
35	145	Notes Receivable - Associated Companies			
36	146	Accounts Receivable - Associated Companies	7,359,210	9,152,754	24.37%
37	151	Fuel Stock	2,011,153	2,051,748	2.02%
38	152	Fuel Stock Expenses Undistributed			
39	153	Residuals and Extracted Products			
40	154	Plant Materials and Operating Supplies	6,079,423	5,924,248	-2.55%
41	155	Merchandise	540,426	722,174	33.63%
42	156	Other Material & Supplies			
43	163	Stores Expense Undistributed			
44	164.1	Gas Stored Underground - Current	9,106,722	10,010,285	9.92%
45	165	Prepayments	6,982,358	7,827,961	12.11%
46	166	Advances for Gas Explor., Devl. & Production			
47	171	Interest & Dividends Receivable	5,846	9,938	70.00%
48	172	Rents Receivable			
49	173	Accrued Utility Revenues	21,172,408	16,040,758	-24.24%
50	174	Miscellaneous Current & Accrued Assets	3,087	671,844	21663.65%
51		**TOTAL Current & Accrued Assets**	$81,085,697	$88,526,650	9.18%

BALANCE SHEET

Year: 1999

	Account Number	& Title	Last Year	This Year	% Change
1		**Assets and Other Debits (cont.)**			
2					
3	**Deferred Debits**				
4					
5	181	Unamortized Debt Expense	$1,662,010	$1,526,835	-8.13%
6	182.1	Extraordinary Property Losses			
7	182.2	Unrecovered Plant & Regulatory Study Costs			
	182.3	Other Regulatory Assets	5,568,013	5,004,456	-10.12%
	183	Prelim. Electric Survey & Investigation Chrg.	240,807	281,397	16.86%
8	183.1	Prelim. Nat. Gas Survey & Investigation Chrg.			
9	183.2	Other Prelim. Nat. Gas Survey & Invtg. Chrgs.			
10	184	Clearing Accounts	(11,705)	(45,832)	291.56%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	5,685,066	5,559,763	-2.20%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	10,995,223	9,513,493	-13.48%
16	190	Accumulated Deferred Income Taxes	21,020,788	19,997,919	-4.87%
17	191	Unrecovered Purchased Gas Costs	(274,040)	(2,578,745)	841.01%
18	192.1	Unrecovered Incremental Gas Costs			
19	192.2	Unrecovered Incremental Surcharges			
20		**TOTAL Deferred Debits**	$44,886,162	$39,259,286	-12.54%
21					
22	**TOTAL ASSETS & OTHER DEBITS**		$931,677,276	$1,047,536,123	12.44%
	Account Number	& Title	Last Year	This Year	% Change
23		**Liabilities and Other Credits**			
24					
25	**Proprietary Capital**				
26					
27	201	Common Stock Issued	$177,398,927	$57,277,915	-67.71%
28	202	Common Stock Subscribed			
29	204	Preferred Stock Issued	16,700,000	16,600,000	-0.60%
30	205	Preferred Stock Subscribed			
31	207	Premium on Capital Stock	174,158,583	375,006,302	115.32%
32	211	Miscellaneous Paid-In Capital			
33	213	(Less) Discount on Capital Stock			
34	214	(Less) Capital Stock Expense	(2,672,372)	(2,694,284)	0.82%
35	216	Appropriated Retained Earnings	36,965,806	39,400,577	6.59%
36	216.1	Unappropriated Retained Earnings	168,616,836	204,168,760	21.08%
37	217	(Less) Reacquired Capital Stock			
38		**TOTAL Proprietary Capital**	$571,167,780	$689,759,270	20.76%
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	43,400,000	43,100,000	-0.69%
46	225	Unamortized Premium on Long Term Debt			
47	226	(Less) Unamort. Discount on Long Term Debt-Dr.	(58,897)	(54,451)	-7.55%
48		**TOTAL Long Term Debt**	$174,191,103	$173,895,549	-0.17%

BALANCE SHEET

Year: 1999

	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	$984,759	$1,257,993	27.75%
9	228.3	Accumulated Provision for Pensions & Benefits	10,979,893	15,204,891	38.48%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	38,594	31,640	-18.02%
12		**TOTAL Other Noncurrent Liabilities**	$12,003,246	$16,494,524	37.42%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable	$15,000,000	$13,000,000	-13.33%
17	232	Accounts Payable	15,320,034	14,280,166	-6.79%
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies	5,016,067	5,143,024	2.53%
20	235	Customer Deposits	1,263,968	1,089,989	-13.76%
21	236	Taxes Accrued	9,801,379	9,727,596	-0.75%
22	237	Interest Accrued	2,315,917	2,284,323	-1.36%
23	238	Dividends Declared	10,799,299	12,170,988	12.70%
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	810,955	863,483	6.48%
27	242	Miscellaneous Current & Accrued Liabilities	5,358,982	6,898,665	28.73%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	$65,686,601	$65,458,234	-0.35%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	$1,173,090	$2,463,919	110.04%
34	253	Other Deferred Credits	8,473,189	5,988,988	-29.32%
35	254	Other Regulatory Liabilities	19,690,485	15,248,052	-22.56%
36	255	Accumulated Deferred Investment Tax Credits	6,114,067	5,226,005	-14.52%
37	256	Deferred Gains from Disposition Of Util. Plant			
38	257	Unamortized Gain on Reacquired Debt			
39	281-283	Accumulated Deferred Income Taxes	73,177,715	73,001,582	-0.24%
40		**TOTAL Deferred Credits**	$108,628,546	$101,928,546	-6.17%
41					
42	**TOTAL LIABILITIES & OTHER CREDITS**		$931,677,276	$1,047,536,123	12.44%

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

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, oil and natural gas 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, oil and natural gas 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 allows 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.

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 oil and natural gas 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 $1.7 million, $1.4 million and $970,000 in 1999, 1998 and 1997, respectively. Property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for oil and natural gas production properties as described below.

In accordance with the provisions of Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," the company reviews the carrying values of its long-lived assets whenever events or changes in circumstances indicate that such carrying values may not be recoverable. As yet, no asset or group of assets has been identified for which the sum of expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset(s) and, accordingly, no impairment losses have been recorded. However, currently unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Oil and natural gas
The company uses the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas 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 oil and natural gas 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 oil and natural gas producing properties. These noncash write-downs amounted to $33.1 million ($20.0 million after tax) and $32.9 million ($19.9 million after tax) for the quarters ended June 30, 1998 and December 31, 1998, respectively.

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 $26.1 million and $11.5 million at December 31, 1999 and 1998, respectively. The remainder of natural gas in underground storage is included in property, plant and equipment and was $46.8 million and $43.7 million at December 31, 1999 and 1998, respectively.

Inventories
Inventories, other than natural gas in underground storage for the company's regulated operations, consist primarily of materials and supplies and inventories held for resale. 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 generally recognizes all other revenues when services are rendered or goods are delivered.

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 24 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. Common stock outstanding includes issued shares less shares held in treasury. Earnings per common share reflect the three-for-two common stock split effected in July 1998 as discussed in Note 7.

Comprehensive income
For the years ended December 31, 1999, 1998 and 1997, comprehensive income equaled net income as reported.

Use of estimates
The preparation of financial statements in conformity with generally accepted accounting principles 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, 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,	1999	1998	1997
		(In thousands)	
Interest, net of amount capitalized	$30,772	$26,394	$25,626
Income taxes	$32,723	$34,498	$18,171

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

Reclassifications
Certain reclassifications have been made in the financial statements for prior years to conform to the current presentation. Such reclassifications had no effect on net income or common stockholders' equity as previously reported.

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). 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 a derivative's gains and losses to offset the related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In June 1999, the FASB issued Statement of Financial Accounting Standards No. 137, "Accounting for Derivative Instruments and Hedging Activities -- Deferral of the Effective Date of FASB Statement No. 133," which delayed the effective date of SFAS No. 133 to fiscal years beginning after June 15, 2000. The company will adopt SFAS No. 133 on January 1, 2001. The company continues to evaluate the effect of adopting SFAS No. 133 but has not yet determined what impact this adoption will have on the company's financial position or results of operations.

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. SAB No. 101 is effective for the first fiscal quarter of the fiscal year beginning after December 15, 1999. SAB No. 101 is not expected to 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:

	1999	1998
	(In thousands)	
Regulatory assets:		
Long-term debt refinancing costs	$ 9,514	$ 10,995
Deferred income taxes	7,274	13,364
Natural gas contract settlement and restructuring costs	3,000	---
Postretirement benefit costs	1,742	2,036
Plant costs	2,835	3,004
Other	6,789	6,063
Total regulatory assets	31,154	35,462
Regulatory liabilities:		
Reserves for regulatory matters	24,231	39,981
Taxes refundable to customers	11,504	14,130
Plant decommissioning costs	6,989	6,413
Deferred income taxes	6,785	7,047
Natural gas costs refundable through rate adjustments	2,579	274
Other	710	157
Total regulatory liabilities	52,798	68,002
Net regulatory position	$ (21,644)	$ (32,540)

As of December 31, 1999, substantially all of the company's regulatory assets are being reflected in rates charged to customers and are being recovered over the next 1 to 17 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

FINANCIAL INSTRUMENTS

Derivatives

From time to time, the company utilizes derivative financial instruments, including price swap and collar agreements and natural gas futures, to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas. The company's policy prohibits the use of derivative instruments for trading purposes 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 an oil price quoted on the New York Mercantile Exchange (NYMEX) or a quoted natural gas price on the NYMEX, Colorado Interstate Gas Index or Williams Gas Index. 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. Amounts payable or receivable on the swap and collar agreements are 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. Gains or losses on futures contracts are deferred until the underlying commodity transaction occurs, at which point they are reported in "Purchased natural gas sold" on the Consolidated Statements of Income.

The following table summarizes hedge agreements entered into by Fidelity Oil Co. and WBI Production, Inc., indirect wholly owned subsidiaries of the company, as of December 31, 1999. These agreements call for Fidelity Oil Co. and WBI Production, Inc. to receive fixed prices and pay variable prices.

(Notional amount and fair value in thousands)

	Weighted Average Fixed Price (Per barrel)	Notional Amount (In barrels)	Fair Value
Oil swap agreements maturing in 2000	$19.55	769	$(1,870)

	Weighted Average Fixed Price (Per MMBtu)	Notional Amount (In MMBtu's)	Fair Value
Natural gas swap agreements maturing in 2000	$2.33	5,307	$597

	Weighted Average Floor/Ceiling Price (Per barrel)	Notional Amount (In barrels)	Fair Value
Oil collar agreement maturing in 2000	$20.00/$22.33	183	$(134)

	Weighted Average Floor/Ceiling Price (Per MMBtu)	Notional Amount (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2000	$2.34/$2.68	3,196	$112

At December 31, 1998, Fidelity Oil Co. had natural gas collar agreements outstanding for 2.9 million MMBtu's of natural gas with a weighted average floor price and ceiling price of $2.10 and $2.51, respectively. The company's net favorable position on the natural gas collar agreements outstanding at December 31, 1998, was $597,000. These agreements call for Fidelity Oil Co. to receive fixed prices and pay variable prices.

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 currently not recorded on the company's financial statements. 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.

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:

	1999		1998	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$ 567,873	$ 555,730	$ 416,456	$ 435,078
Preferred stock subject to mandatory redemption	$ 1,600	$ 1,418	$ 1,700	$ 1,592

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 $81.9 million at December 31, 1999. 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 $14.7 million at December 31, 1999, and $15 million at December 31, 1998. The weighted average interest rate for borrowings outstanding at December 31, 1999 and 1998, was 6.97 percent and 5.45 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:

	1999	1998
	(In thousands)	
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
Pollution control note obligation, 6.20%, due March 1, 2004	3,100	3,400
Senior notes at a weighted average rate of 7.19%, due on dates ranging from December 31, 2000 to October 30, 2018	151,400	141,000
Commercial paper at a weighted average rate of 6.80%, supported by a revolving credit agreement due on September 1, 2002	223,169	82,921
Revolving lines of credit at a weighted average rate of 8.37%, due on dates ranging from November 1, 2001 through December 31, 2002	45,900	45,200
Term credit agreements at a weighted average rate of 7.52%, due on dates ranging from January 1, 2000 through November 25, 2012	13,970	13,211
Other	(516)	(126)
Total long-term debt	567,873	416,456
Less current maturities	4,328	3,192
Net long-term debt	$ 563,545	$ 413,264

Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the company, has a revolving credit agreement with various banks on behalf of its subsidiaries that allows for borrowings of up to $240 million. This facility supports the Centennial commercial paper program. Under the Centennial commercial paper program, $223.2 million and $82.9 million were outstanding at December 31, 1999 and 1998, respectively. The commercial paper borrowings are classified as long term as the company intends to refinance these borrowings on a long term basis through continued commercial paper borrowings supported by the revolving credit agreement due September 1, 2002. The company intends to renew this existing credit agreement on an annual basis.

Effective December 27, 1999, Centennial entered into an uncommitted long-term master shelf agreement with The Prudential Insurance Company of America on behalf of its subsidiaries that allows for borrowings of up to $200 million, none of which was outstanding at December 31, 1999.

Under the revolving lines of credit, the company and certain subsidiaries have $58.2 million available as of December 31, 1999. Amounts outstanding under the revolving lines of credit were $45.9 million and $45.2 million at December 31, 1999 and 1998, respectively.

The amounts of scheduled long-term debt maturities for the five years following December 31, 1999 aggregate $4.3 million in 2000; $24.6 million in 2001; $272.3 million in 2002; $6.6 million in 2003 and $21.6 million in 2004.

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 $287 million of additional first mortgage bonds at December 31, 1999. 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, 1999.

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

	1999	1998
	(Dollars in thousands)	
Authorized:		
Preferred --		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A --		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference --		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
Subject to mandatory redemption --		
Preferred --		
5.10% Series -- 16,000 shares in 1999 and 17,000 shares in 1998	$ 1,600	$ 1,700
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	16,600	16,700
Less sinking fund requirements	100	100
Net preferred stocks	$ 16,500	$ 16,600

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.

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, 1999, is $100,000.

NOTE 7
COMMON STOCK
At the Annual Meeting of Stockholders held on April 27, 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 the stock split.

The company's Automatic Dividend Reinvestment and Stock Purchase Plan (DRIP) provides participants in the DRIP 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 DRIP. 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 DRIP 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 DRIP 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 DRIP. At December 31, 1999, there were 8.1 million shares of common stock reserved for original issuance under the DRIP 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. Under the stock option plans, the company is authorized to grant options for up to 4.3 million shares of common stock and has granted options on 1.9 million shares through December 31, 1999.

Had the company recorded compensation expense for the fair value of options granted consistent with SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123), net income would have been reduced on a pro forma basis by $498,000 in 1999, $820,000 in 1998 and $51,400 in 1997. On a pro forma basis, basic and diluted earnings per share for 1999 and 1998 would have been reduced by $.01 and $.02, respectively, and there would have been no effect for 1997. Since SFAS No. 123 does not require this accounting to be applied to options granted prior to January 1, 1995, the resulting pro forma compensation costs may not be representative of those to be expected in future years.

A summary of the status of the stock option plans at December 31, 1999, 1998 and 1997, and changes during the years then ended are as follows:

	1999		1998		1997	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	1,516,808	$19.17	594,180	$12.07	635,965	$11.77
Granted	22,500	23.31	1,225,920	21.12	22,500	16.37
Forfeited	(57,966)	20.38	(37,875)	21.05	(13,600)	11.41
Exercised	(54,080)	11.95	(265,417)	11.98	(50,685)	10.50
Balance at end						

of year	1,427,262	19.46	1,516,808	19.17	594,180	12.07
Exercisable at end of year	301,681	$13.89	333,261	$12.94	112,461	$11.67

Exercise prices on options outstanding at December 31, 1999, range from $10.50 to $23.84 with a weighted average remaining contractual life of approximately 8 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:

	1999	1998	1997
Fair value of options at grant date	$ 4.82	$ 2.40	$ 2.09
Weighted average risk-free interest rate	5.98%	4.78%	6.60%
Weighted average expected price volatility	22.03%	16.27%	14.51%
Weighted average expected dividend yield	4.22%	5.13%	5.48%
Expected life in years	7	7	7

NOTE 8

INCOME TAXES

Income tax expense is summarized as follows:

Years ended December 31,	1999	1998 (In thousands)	1997
Current:			
Federal	$ 29,574	$ 28,256	$ 15,427
State	3,874	5,880	2,362
Foreign	158	605	60
	33,606	34,741	17,849
Deferred:			
Investment tax credit	(888)	(975)	(1,150)
Income taxes --			
Federal	12,902	(14,214)	11,844
State	3,690	(2,067)	2,200
	15,704	(17,256)	12,894
Total income tax expense	$ 49,310	$ 17,485	$ 30,743

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

	1999	1998
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 14,562	$ 22,319
Accrued pension costs	10,898	9,274
Deferred investment tax credits	2,028	2,336
Accrued land reclamation	2,803	2,907

Other	16,892	17,572
Total deferred tax assets	47,183	54,408
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	218,355	188,375
Basis differences on oil and natural gas producing properties	17,163	9,604
Regulatory matters	6,785	7,047
Other	3,051	5,558
Total deferred tax liabilities	245,354	210,584
Net deferred income tax liability	$ (198,171)	$ (156,176)

The following table reconciles the change in the net deferred income tax liability from December 31, 1998, to December 31, 1999, to the deferred income tax expense included in the Consolidated Statements of Income:

	1999 (In thousands)
Net change in deferred income tax liability from the preceding table	$ 41,995
Change in tax effects of income tax-related regulatory assets and liabilities	(4,293)
Deferred taxes associated with acquisitions	(21,110)
Deferred income tax expense for the period	$ 16,592

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,	1999		1998		1997	
	Amount	%	Amount	%	Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	$ 46,686	35.0	$ 18,057	35.0	$ 29,876	35.0
Increases (reductions) resulting from:						
Depletion allowance	(1,300)	(1.0)	(1,571)	(3.0)	(828)	(1.0)
State income taxes -- net of federal income tax benefit	5,921	4.4	2,312	4.5	3,473	4.1
Investment tax credit amortization	(888)	(.6)	(975)	(1.9)	(1,150)	(1.4)
Other items	(1,109)	(.8)	(338)	(.7)	(628)	(.7)
Total income tax expense	$ 49,310	37.0	$ 17,485	33.9	$ 30,743	36.0

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. Prior to the fourth quarter of 1999, the company reported five operating segments consisting of electric, natural gas distribution, natural gas transmission, construction materials and mining, and oil and natural gas production. During the fourth quarter of 1999, the company revised the components of the segments reported based on organizational changes and the significance of current segments. As a result, a utility services segment was separated from the electric segment; gas production activities previously included in the natural gas transmission segment are now reflected in the oil and natural gas production segment; and the remaining operations of the natural gas transmission business were renamed pipeline and energy services.

The company's operations are now conducted through six business segments and all prior period information has been restated to reflect this change. As of December 31, 1999, 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, and these operations also supply related value-added products and services in the Northern Great Plains. The utility services business is a full-service engineering, design and build company operating in the western United States specializing in construction and maintenance of power and natural gas distribution and transmission systems as well as communication and fiber optic facilities. The pipeline and energy services business provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems and provides energy marketing and management services throughout the United States. The oil and natural gas production business is engaged in oil and natural gas acquisition, exploration and production throughout 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. It also operates lignite coal mines in Montana and North Dakota.

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:

	1999	1998	1997
		(In thousands)	
Operating revenues - external:			
Electric	$ 154,869	$ 147,221	$ 141,590
Natural gas distribution	157,692	154,147	157,005
Utility services	99,917	64,232	22,761
Pipeline and energy services	334,188	132,826	36,999
Oil and natural gas production	63,238	51,750	75,172
Construction materials and mining	455,939	331,988	163,006
Total operating revenues - external	$ 1,265,843	$ 882,164	$ 596,533
Operating revenues - intersegment:			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	---	---	---
Pipeline and energy services	49,344	47,906	50,019
Oil and natural gas production	15,156	10,092	2,744
Construction materials and mining(a)	13,966	14,463	11,141

Intersegment eliminations		(64,500)		(57,998)		(52,763)
Total operating revenues - intersegment(a)	$	13,966	$	14,463	$	11,141
Depreciation, depletion and amortization:						
Electric	$	18,375	$	18,129	$	17,491
Natural gas distribution		7,348		7,150		7,013
Utility services		2,591		1,669		280
Pipeline and energy services		8,248		6,972		4,888
Oil and natural gas production		19,248		23,304		25,096
Construction materials and mining		26,008		20,562		10,999
Total depreciation, depletion and amortization	$	81,818	$	77,786	$	65,767
Interest expense:						
Electric	$	9,692	$	9,979	$	10,735
Natural gas distribution		3,614		3,728		3,698
Utility services		812		325		214
Pipeline and energy services		7,281		5,800		8,117
Oil and natural gas production		3,405		3,039		2,942
Construction materials and mining		11,202		7,402		4,503
Total interest expense	$	36,006	$	30,273	$	30,209
Income taxes:						
Electric	$	8,678	$	7,767	$	7,011
Natural gas distribution		1,443		2,681		2,987
Utility services		4,323		2,437		631
Pipeline and energy services		13,356		12,579		7,566
Oil and natural gas production		10,032		(23,134)		8,156
Construction materials and mining		11,478		15,155		4,392
Total income taxes	$	49,310	$	17,485	$	30,743
Earnings on common stock:						
Electric	$	15,973	$	13,908	$	12,441
Natural gas distribution		3,192		3,501		4,514
Utility services		6,505		3,272		947
Pipeline and energy services		20,972		18,651		9,955
Oil and natural gas production		16,207		(30,501)(b)		15,867
Construction materials and mining		20,459		24,499		10,111
Total earnings on common stock	$	83,308	$	33,330	$	53,835
Capital expenditures:						
Electric	$	18,218	$	13,035	$	18,363
Natural gas distribution		9,246		8,256		8,858
Utility services		16,052		18,343		9,607
Pipeline and energy services		35,123		17,603		9,684
Oil and natural gas production		64,294		100,572		34,172
Construction materials and mining		105,098		172,108		41,472
Net proceeds from sale or						

disposition of property	(16,660)	(4,275)	(4,522)
Total net capital expenditures	$ 231,371	$ 325,642	$ 117,634
Identifiable assets:			
Electric(c)	$ 307,417	$ 305,627	
Natural gas distribution(c)	131,294	129,654	
Utility services	67,755	38,677	
Pipeline and energy services	302,587	239,507	
Oil and natural gas production	255,416	192,642	
Construction materials and mining	655,499	500,720	
Corporate assets(d)	46,335	45,948	
Total identifiable assets	$ 1,766,303	$ 1,452,775	
Property, plant and equipment:			
Electric	$ 581,090	$ 567,282	
Natural gas distribution	185,797	178,522	
Utility services	21,876	15,765	
Pipeline and energy services	308,409	276,325	
Oil and natural gas production	343,157	288,487	
Construction materials and mining	601,952	484,419	
Less accumulated depreciation, depletion and amortization	794,105	726,123	
Net property, plant and equipment	$ 1,248,176	$ 1,084,677	

(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 oil and natural gas 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 1999, 1998 and 1997, related to acquisitions, in the preceding table include the following noncash transactions: issuance of the company's equity securities in 1999 of $77.5 million; issuance of the company's equity securities, less treasury stock acquired, in 1998 of $138.8 million; and assumed debt and the issuance of the company's equity securities in total for 1997 of $9.9 million.

NOTE 10
ACQUISITIONS

In 1999, the company acquired a number of businesses, none of which were 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 were 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.

In 1997, the company acquired several businesses, none of which were individually material, including the remaining 50 percent interest in Hawaiian Cement (See Note 12) and utility services construction and construction supplies and equipment businesses in Oregon. The total purchase consideration, consisting of the company's common stock and cash, for these businesses was $35.2 million.

The above acquisitions were accounted for under the purchase method of accounting and accordingly, the acquired assets and liabilities assumed have been recorded at their respective fair values as of the date of acquisition. The results of operations of the acquired businesses 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, 1999 and 1998. Changes in benefit obligation and plan assets for the years ended December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	1999	1998	1999	1998
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$187,665	$178,199	$ 70,338	$ 73,838
Service cost	4,894	4,509	1,451	1,502
Interest cost	12,573	12,248	4,720	4,848
Plan participants' contributions	---	---	617	475
Amendments	3,612	437	3,691	(4,810)
Actuarial (gain) loss	(17,134)	5,971	(11,047)	(1,695)
Benefits paid	(10,613)	(13,699)	(3,831)	(3,820)
Benefit obligation at end of year	180,997	187,665	65,939	70,338

Change in plan assets:

Fair value of plan assets at

beginning of year	251,194	225,201	39,543	30,595
Actual return on plan assets	35,874	39,604	5,223	6,226
Employer contribution	4	88	5,595	6,067
Plan participants' contributions	---	---	617	475
Benefits paid	(10,613)	(13,699)	(3,831)	(3,820)
Fair value of plan assets at end of year	276,459	251,194	47,147	39,543
Funded status	95,462	63,529	(18,792)	(30,795)
Unrecognized actuarial gain	(108,593)	(73,963)	(21,299)	(8,036)
Unrecognized prior service cost	10,206	7,645	---	(1,433)
Unrecognized net transition obligation (asset)	(4,402)	(5,340)	30,910	31,029
Accrued benefit cost	$ (7,327)	$ (8,129)	$ (9,181)	$ (9,235)

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	
	1999	1998	1999	1998
Discount rate	7.75%	6.75%	7.75%	6.75%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	5.00%	4.50%	5.00%	4.50%

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

	1999	1998
Health care trend rate	6.00%-8.00%	6.50%-8.50%
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,	1999	1998	1997	1999	1998	1997
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	$ 4,894	$ 4,509	$ 3,889	$ 1,451	$ 1,502	$ 1,272
Interest cost	12,573	12,248	11,651	4,720	4,848	4,691
Expected return on assets	(17,489)	(15,892)	(14,321)	(2,807)	(2,395)	(1,748)
Amortization of prior service cost	842	848	811	---	---	---
Recognized net actuarial gain	(995)	(621)	(666)	(200)	(169)	(105)

Amortization of net transition obligation (asset)	(997)	(994)	(988)	2,377	2,458	2,458
Net periodic benefit cost (income)	(1,172)	98	376	5,541	6,244	6,568
Less amount capitalized	(87)	79	70	463	628	625
Net periodic benefit expense (income)	$ (1,085)	$ 19	$ 306	$ 5,078	$ 5,616	$ 5,943

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, 1999:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 240	$ (217)
Effect on postretirement benefit obligation	$3,004	$ (2,683)

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 $3.3 million, $2.7 million and $2.2 million in 1999, 1998 and 1997, respectively.

The company sponsors various defined contribution plans for eligible employees. Costs incurred by the company under these plans were $4.4 million in 1999, $3.1 million in 1998 and $2.1 million in 1997. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 12

PARTNERSHIP INVESTMENT

In September 1995, KRC Holdings, Inc., through its wholly owned subsidiary, Knife River Hawaii, Inc., acquired a 50 percent interest in Hawaiian Cement, which was previously owned by Lone Star Industries, Inc. Knife River Dakota, Inc., a wholly owned subsidiary of KRC Holdings, Inc. acquired the remaining 50 percent interest in Hawaiian Cement from the previous owner, Adelaide Brighton Cement (Hawaii), Inc. of Adelaide, Australia, in July 1997.

In August 1997, the company began consolidating Hawaiian Cement into its financial statements. Prior to August 1997, the company's net investment in Hawaiian Cement was not consolidated and was accounted for by the equity method. The company's share of operating results for the seven months ended July 1, 1997, is included in "Other income - net" in the accompanying Consolidated Statements of Income for the year ended December 31, 1997. Summarized operating results for Hawaiian Cement for the seven months ended July 31, 1997, when accounted for by the equity method, are as follows: net sales of $33.5 million, operating margin of $4.7 million and income before income taxes of $2.0 million.

NOTE 13

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:

	1999	1998
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 49,889	$ 49,762
Less accumulated depreciation	29,611	28,781
	$ 20,278	$ 20,981
Coyote Station:		
Utility plant in service	$ 121,919	$ 121,726
Less accumulated depreciation	60,350	56,770
	$ 61,569	$ 64,956

NOTE 14

REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

Williston Basin Interstate Pipeline Company, an indirect wholly owned subsidiary of the company, had pending with the FERC a general natural gas rate change application implemented in 1992. In October 1997, Williston Basin appealed to the United States Court of Appeals for the D.C. Circuit (D.C. Circuit Court) certain issues decided by the FERC in orders concerning the 1992 proceeding. On January 22, 1999, the D.C. Circuit Court issued its opinion remanding the issues of return on equity, ad valorem taxes and throughput to the FERC for further explanation and justification. The mandate was issued by the D.C. Circuit Court to the FERC on March 11, 1999. By order dated June 1, 1999, the FERC remanded the return on equity issue to an Administrative Law Judge for further proceedings. On October 13, 1999, the FERC approved a settlement proposed by the parties to the proceeding which resolves the remanded return on equity issue and concludes the proceeding. Based on the FERC's approval of this settlement, Williston Basin sought reimbursement from its customers in the fourth quarter of 1999 of a portion of the refunds made in 1997 relating to the return on equity issue.

In June 1995, Williston Basin filed a general rate increase application with the 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. On June 1, 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. On July 1, 1999, Williston Basin requested rehearing of certain issues which were contained in the June 1, 1999 FERC order. On September 29, 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, on October 29, 1999, Williston Basin issued refunds to its customers totaling $11.3 million, all from amounts which had previously been reserved. In mid-December 1999, a hearing was held before the FERC regarding the return on equity issue. In addition, on July 29, 1999, Williston Basin appealed to the D.C. Circuit Court certain issues concerning storage cost allocations as decided by the FERC in its June 1, 1999 order. On October 12, 1999, the D.C. Circuit Court issued an order which dismissed Williston Basin's appeal but permitted Williston Basin to again appeal such previously contested issues upon final determination of all issues by the FERC in this proceeding.

On December 1, 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin will begin 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 June 1, 1999 FERC orders referenced above, Williston Basin in the second quarter of 1999 determined that reserves it had previously established exceeded its expected refund obligation and, accordingly, reversed reserves in the amount of $4.4 million after tax. Williston Basin believes that its remaining reserves are adequate based on its assessment of the ultimate outcome of the various proceedings.

NOTE 15
COMMITMENTS AND CONTINGENCIES
Litigation
In November 1993, the estate of W.A. Moncrief (Moncrief), a producer from whom Williston Basin purchased a portion of its natural gas supply, filed suit in Federal District Court for the District of Wyoming (Federal District Court) against Williston Basin and the company disputing certain price and volume issues under the contract.

Through the course of this action Moncrief submitted damage calculations which totaled approximately $19 million or, under its alternative pricing theory, approximately $39 million.

In June 1997, the Federal District Court issued its order awarding Moncrief damages of approximately $15.6 million. In July 1997, the Federal District Court issued an order limiting Moncrief's reimbursable costs to post-judgment interest, instead of both pre- and post-judgment interest as Moncrief had sought. In August 1997, Moncrief filed a notice of appeal with the United States Court of Appeals for the Tenth Circuit (U.S. Court of Appeals) related to the Federal District Court's orders. In September 1997, Williston Basin and the company filed a notice of cross-appeal.

On April 20, 1999, the U.S. Court of Appeals issued its order which affirmed in part and reversed in part the Federal District Court's June 1997 decision. Additionally, the U.S. Court of Appeals remanded the case to the Federal District Court for further determination of the prices and volumes to be used for determination of damages. The U.S. Court of Appeals also remanded to the lower court for further consideration the issue of whether pre-judgment interest on damages is recoverable by Moncrief. As a result of the decision by the U.S. Court of Appeals, the prior judgment of $15.6 million by the Federal District Court was vacated. On December 8, 1999, a settlement was entered into between Williston Basin and Moncrief whereby Williston Basin paid Moncrief $3.0 million in settlement of all claims. On December 28, 1999, the United States District Court, District of Wyoming dismissed the case.

Williston Basin believes that it is entitled to recover from customers virtually all of the costs which were incurred as a result of the settlement of this litigation as gas supply realignment transition costs pursuant to the provisions of the FERC's Order 636. However, the amount of costs that can ultimately be recovered is subject to approval by the FERC and market conditions.

In December 1993, Apache Corporation (Apache) and Snyder Oil Corporation (Snyder) filed suit in North Dakota Northwest Judicial District Court (North Dakota District Court) against Williston Basin and the company. Apache and Snyder are oil and natural gas producers which had processing agreements with Koch Hydrocarbon Company (Koch). Williston Basin and the company had a natural gas purchase contract with Koch. Apache and Snyder alleged they were entitled to damages for the breach of Williston Basin's and the company's contract with Koch. Apache and Snyder submitted damage estimates under differing theories aggregating up to $4.8 million without interest. In November 1998, the North Dakota District Court entered an order directing the entry of judgment in favor of Williston Basin and the company. On March 31, 1999, judgment was entered, thereby dismissing Apache and Snyder's claims against Williston Basin and the company. Apache and Snyder filed a notice of appeal with the North Dakota Supreme Court on May 17, 1999. On December 28, 1999, the North Dakota Supreme Court affirmed the decision of the North Dakota District Court, thereby dismissing Apache and Snyder's claims against Williston Basin and the company.

In a related matter, in March 1997, a suit was filed by 11 other producers, several of which had unsuccessfully tried to intervene in the Apache and Snyder litigation, against Koch, Williston Basin and the company. The parties to this suit are making claims similar to those in the Apache and Snyder litigation, although no specific damages have been stated.

In Williston Basin's opinion, the claims of the 11 other producers are without merit. If any amounts are ultimately found to be due, Williston Basin plans to file with the FERC for recovery from customers. However, the amount of costs that can ultimately be recovered is subject to approval by the FERC and market conditions.

In November 1995, a suit was filed in District Court, County of Burleigh, State of North Dakota (State District Court) by Minnkota Power Cooperative, Inc., Otter Tail Power Company, Northwestern Public Service Company and Northern Municipal Power Agency (Co-owners), the owners of an aggregate 75 percent interest in the Coyote electric generating station (Coyote Station), against the company (an owner of a 25 percent interest in the Coyote Station) and Knife River. In its complaint, the Co-owners alleged a breach of contract against Knife River with respect to the long-term coal supply agreement (Agreement) between the owners of the Coyote Station and Knife River. The Co-owners requested a determination by the State District Court of the pricing mechanism to be applied to the Agreement and further requested damages during the term of such alleged breach on the difference between the prices charged by Knife River and the prices that may ultimately be determined by the State District Court. The Co-owners also alleged a breach of fiduciary duties by the company as operating agent of the Coyote Station, asserting essentially that the company was unable to cause Knife River to reduce its coal price sufficiently under the Agreement, and the Co-owners sought damages in an unspecified amount. In May 1996, the State District Court stayed the suit filed by the Co-owners pending arbitration, as provided for in the Agreement.

In September 1996, the Co-owners notified the company and Knife River of their demand for arbitration of the pricing dispute that had arisen under the Agreement. The demand for arbitration, filed with the American Arbitration Association (AAA), did not make any direct claim against the company in its capacity as operator of the Coyote Station. The Co-owners requested that the arbitrators make a determination that the prices charged by Knife River were excessive and that the Co-owners be awarded damages, based upon the difference between the prices that Knife River charged and a "fair and equitable" price. Upon application by the company and Knife River, the AAA administratively determined that the company was not a proper party defendant to the arbitration, and the arbitration proceeded against Knife River. In October 1998, a hearing before the arbitration panel was completed. At the hearing the Co-owners requested damages of approximately $24 million, including interest, plus a reduction in the future price of coal under the Agreement. During 1999, the arbitration panel issued three Memorandum Opinions (Opinions) and held an additional hearing. Based on its assessment of the proceedings, Knife River's earnings in the second quarter of 1999 reflected a $3.7 million after-tax charge regarding this matter. As a result of the Memorandum Opinion rendered by the arbitrators in August 1999, Knife River's 1999 third quarter earnings included a $1.9 million after-tax charge reflecting the resolution of this matter. The arbitration panel also revised the pricing terms of the Agreement beginning April 1, 1999. The revised pricing terms retained the minimum return on sales provision but at a lower guaranteed level than the Agreement previously provided.

On January 5, 2000, the State District Court entered a judgment agreed to by all parties that dismissed the company from the action, confirmed the Opinions of the arbitration panel, filed the Opinions under seal pursuant to a confidentiality agreement among the parties, held that each party shall bear its own costs subject to any contractual agreements to the contrary, dismissed the November 1995 action, and confirmed that all sums due pursuant to the arbitration have been paid and satisfied.

On June 3, 1999, several oil and gas royalty interest owners filed suit in Colorado State District Court, in the City and County of Denver, against WBI Production, Inc. (WBI Production), an indirect wholly owned subsidiary of the company, and several former producers of natural gas with respect to certain gas production properties in the state of Colorado. The complaint arose as a result of the purchase by WBI Production effective January 1, 1999, of certain natural gas producing leaseholds from the former producers. Prior to February 1, 1999, the natural gas produced from the leaseholds was sold at above market prices pursuant to a natural gas contract. Pursuant to the contract, the royalty interest owners were paid royalties based upon the above market prices. The royalty interest owners have alleged that WBI Production took assignment of the rights to the natural gas contract from the former owner of the contract and, with respect to natural gas produced from such leases and sold at market prices thereafter, wrongly ceased paying the higher royalties on such gas.

In their complaint, the royalty interest owners have alleged, in part, breach of oil and gas lease obligations and unjust enrichment on the part of WBI Production and the other former producers with respect to the amount of royalties being paid to the royalty interest owners. The royalty interest owners have requested damages for additional royalties and other costs, including pre-judgment interest. No specific amount of damages has been stated. Trial before the Colorado State District Court has been scheduled for April 24, 2000. WBI Production intends to vigorously contest the suit.

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 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.

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. The suit has been removed to the U.S. District Court, District of Kansas. The defendants in this suit have filed a motion to have the suit transferred to Wyoming and consolidated with the Grynberg proceedings.

Williston Basin and Montana-Dakota believe the claims of Grynberg and Quinque are without merit and intend to vigorously contest these suits.

Other

During the third quarter of 1999, the company and Williston Basin reached resolution with respect to certain production tax and other state tax matters that had been outstanding, some dating back to 1989. Deficiency claims of approximately $5.6 million, plus interest, had been received with respect to these issues. As a result in September 1999, Williston Basin reversed reserves which were no longer needed in an amount of $3.9 million after tax.

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.

Electric purchased power commitments
Through October 31, 2006, Montana-Dakota has contracted to purchase 66,400 kW of participation power 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 from Black Hills Power and Light Company.

NOTE 16
QUARTERLY DATA (UNAUDITED)
The following unaudited information shows selected items by quarter for the years 1999 and 1998:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
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
1998*				
Operating revenues	$ 170,122	$ 179,715	$ 269,978	$ 276,812
Operating expenses	137,913	186,310	227,283	274,178
Operating income (loss)	32,209	(6,595)	42,695	2,634
Net income (loss)	17,793	(5,785)	22,538	(439)
Earnings (loss) per common share:				
Basic	.39	(.12)	.42	(.01)
Diluted	.39	(.12)	.42	(.01)
Weighted average common shares outstanding:				
Basic	45,375	50,936	52,703	53,021
Diluted	45,629	50,936	53,062	53,021

* Reflects $20.0 million and $19.9 million in noncash after-tax write-downs of oil and natural gas properties for the second quarter and fourth quarter of 1998, respectively.

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 17

OIL AND NATURAL GAS ACTIVITIES (UNAUDITED)

Fidelity Exploration & Production Company, an indirect wholly owned subsidiary of the company, is involved in the acquisition, exploration, development and production of oil and natural gas 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 throughout the United States and in the Gulf of Mexico in proportion to its interests.

Fidelity also owns in fee or holds natural gas leases for the properties it operates in Montana, North Dakota and Colorado. These rights are in the Cedar Creek Anticline in southeastern Montana, in the Bowdoin area located in north-central Montana and the Bonny Field located in eastern Colorado.

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

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

	1999	1998	1997
		(In thousands)	
Subject to amortization	$ 319,448	$ 266,301	$ 252,291
Not subject to amortization	23,464	22,153	9,408
Total capitalized costs	342,912	288,454	261,699
Less accumulated depreciation, depletion and amortization	129,211	111,472	95,611
Net capitalized costs	$ 213,701	$ 176,982	$ 166,088

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

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

Years ended December 31,	1999	1998	1997
		(In thousands)	
Acquisitions	$ 30,842	$ 63,419	$ 59
Exploration	11,010	15,976	13,344
Development	21,822	21,148	18,874
Total capital expenditures	$ 63,674	$ 100,543	$ 32,277

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

Years ended December 31,	1999	1998	1997
		(In thousands)	
Revenues	$ 75,327	$ 61,831	$ 77,756
Production costs	25,402	19,419	23,251
Depreciation, depletion and amortization	19,136	23,050	24,864
Write-downs of oil and natural gas properties (Note 1)	---	66,000	---
Pretax income	30,789	(46,638)	29,641
Income tax expense (benefit)	11,815	(19,268)	10,968
Results of operations for producing activities	$ 18,974	$ (27,370)	$ 18,673

The following table summarizes the company's estimated quantities of proved oil and natural gas reserves at December 31, 1999, 1998 and 1997, and reconciles the changes between these dates. Estimates of economically recoverable oil and natural gas 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.

	1999		1998		1997	
	Oil	Natural Gas	Oil	Natural Gas	Oil	Natural Gas
	(In thousands of barrels/Mcf)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	11,500	243,600	14,900	184,900	16,100	200,200
Production	(1,800)	(24,700)	(1,900)	(20,700)	(2,100)	(20,400)
Extensions and discoveries	800	21,800	200	21,300	600	12,100
Purchases of proved reserves	700	38,200	2,000	56,600	---	200
Sales of reserves in place	(400)	(9,300)	---	(100)	(200)	(2,300)
Revisions to previous estimates due to improved secondary recovery techniques and/or changed economic conditions	3,900	(700)	(3,700)	1,600	500	(4,900)
Balance at end of year	14,700	268,900	11,500	243,600	14,900	184,900
Proved developed reserves:						
January 1, 1997	15,400	168,200				

December 31, 1997	14,500	163,800
December 31, 1998	10,700	193,000
December 31, 1999	13,300	213,400

All of the company's interests in oil and natural gas 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 oil and natural gas interests at December 31 is as follows:

	1999	1998 (In thousands)	1997
Future net cash flows before income taxes	$ 492,000	$ 246,700	$ 306,600
Future income tax expenses	131,500	40,500	86,600
Future net cash flows	360,500	206,200	220,000
10% annual discount for estimated timing of cash flows	131,400	81,100	81,000
Discounted future net cash flows relating to proved oil and natural gas reserves	$ 229,100	$ 125,100	$ 139,000

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

	1999	1998 (In thousands)	1997
Beginning of year	$ 125,100	$ 139,000	$ 234,000
Net revenues from production	(49,900)	(42,400)	(54,500)
Change in net realization	123,100	(70,500)	(158,400)
Extensions, discoveries and improved recovery, net of future production-related costs	33,500	18,200	19,400
Purchases of proved reserves	57,700	51,000	200
Sales of reserves in place	(14,700)	(100)	(2,800)
Changes in estimated future development costs, net of those incurred during the year	(9,800)	(16,600)	7,700
Accretion of discount	16,700	18,600	32,800
Net change in income taxes	(59,800)	30,100	62,100
Revisions of previous quantity estimates	7,400	(1,600)	(1,300)
Other	(200)	(600)	(200)
Net change	104,000	(13,900)	(95,000)
End of year	$ 229,100	$ 125,100	$ 139,000

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end oil and natural gas prices. 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.

NOTE 18

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 $371,553,478 and $322,000,585; current and accrued assets would increase by $263,169,598 and $159,563,049; deferred debits would increase by $84,043,514 and $39,533,812; preferred stock would decrease by $100,000 and $100,000; long-term debt would increase by $389,649,471 and $239,072,884; other noncurrent liabilities and current and accrued liabilities would increase by $105,374,079 and $91,779,591; deferred credits would increase by $227,468,852 and $193,970,783 as of December 31, 1999 and 1998, respectively. Furthermore, operating revenues would increase by $967,248,297 and $595,259,613; and operating expenses, excluding income taxes, would increase by $849,912,662 and $564,511,507 for the year ended December 31, 1999 and 1998, respectively. In addition, net cash provided by operating activities would increase by $107,314,000; net cash used in investing activities would increase by $110,748,000; net cash provided by financing activities would increase by $39,730,000; and the net change in cash and cash equivalents would increase by $36,296,000 for the year ended December 31, 1999. 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: 1999

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Intangible Plant**			
3					
4	301	Organization			
5	302	Franchises & Consents			
6	303	Miscellaneous Intangible Plant	$1,489,115	$2,190,508	47.10%
7					
8		**TOTAL Intangible Plant**	$1,489,115	$2,190,508	47.10%
9					
10		**Production Plant**			
11					
12	Steam Production				
13					
14	310	Land & Land Rights	$210,115	$249,149	18.58%
15	311	Structures & Improvements	9,790,434	9,706,557	-0.86%
16	312	Boiler Plant Equipment	33,549,861	33,027,992	-1.56%
17	313	Engines & Engine Driven Generators			
18	314	Turbogenerator Units	7,471,019	7,589,906	1.59%
19	315	Accessory Electric Equipment	3,079,602	3,016,645	-2.04%
20	316	Miscellaneous Power Plant Equipment	2,383,837	3,194,105	33.99%
21					
22		**TOTAL Steam Production Plant**	$56,484,868	$56,784,354	0.53%
23					
24	Nuclear Production				
25					
26	320	Land & Land Rights			
27	321	Structures & Improvements			
28	322	Reactor Plant Equipment		NOT	
29	323	Turbogenerator Units		APPLICABLE	
30	324	Accessory Electric Equipment			
31	325	Miscellaneous Power Plant Equipment			
32					
33		**TOTAL Nuclear Production Plant**			
34					
35	Hydraulic Production				
36					
37	330	Land & Land Rights			
38	331	Structures & Improvements			
39	332	Reservoirs, Dams & Waterways		NOT	
40	333	Water Wheels, Turbines & Generators		APPLICABLE	
41	334	Accessory Electric Equipment			
42	335	Miscellaneous Power Plant Equipment			
43	336	Roads, Railroads & Bridges			
44					
45		**TOTAL Hydraulic Production Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 1999

	Account Number & Title		Last Year	This Year	% Change
1					
2		Production Plant (cont.)			
3					
4	Other Production				
5					
6	340	Land & Land Rights	$9,269	$9,079	-2.05%
7	341	Structures & Improvements	58,465	57,265	-2.05%
8	342	Fuel Holders, Producers & Accessories	66,440	65,075	-2.05%
9	343	Prime Movers			
10	344	Generators	2,106,772	2,063,509	-2.05%
11	345	Accessory Electric Equipment	41,027	114,792	179.80%
12	346	Miscellaneous Power Plant Equipment	7,025	6,260	-10.89%
13					
14		**TOTAL Other Production Plant**	$2,288,998	$2,315,980	1.18%
15					
16		**TOTAL Production Plant**	$58,773,866	$59,100,334	0.56%
17					
18		**Transmission Plant**			
19					
20	350	Land & Land Rights	$634,591	$633,993	-0.09%
21	352	Structures & Improvements	430	421	-2.09%
22	353	Station Equipment	11,973,797	11,870,228	-0.86%
23	354	Towers & Fixtures	1,050,544	1,029,056	-2.05%
24	355	Poles & Fixtures	5,619,903	5,594,432	-0.45%
25	356	Overhead Conductors & Devices	5,446,632	5,384,840	-1.13%
26	357	Underground Conduit			
27	358	Underground Conductors & Devices			
28	359	Roads & Trails			
29					
30		**TOTAL Transmission Plant**	$24,725,897	$24,512,970	-0.86%
31					
32		**Distribution Plant**			
33					
34	360	Land & Land Rights	$245,067	$247,129	0.84%
35	361	Structures & Improvements			
36	362	Station Equipment	3,692,062	3,754,456	1.69%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	4,910,343	5,054,013	2.93%
39	365	Overhead Conductors & Devices	3,832,265	3,967,849	3.54%
40	366	Underground Conduit	12,967	12,967	
41	367	Underground Conductors & Devices	3,403,104	3,628,593	6.63%
42	368	Line Transformers	5,451,634	5,607,061	2.85%
43	369	Services	3,060,020	3,125,859	2.15%
44	370	Meters	1,982,760	2,009,389	1.34%
45	371	Installations on Customers' Premises	445,479	458,208	2.86%
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems	1,470,674	1,490,359	1.34%
48					
49		**TOTAL Distribution Plant**	$28,506,375	$29,355,883	2.98%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED) Year: 1999

	Account Number & Title		Last Year	This Year	% Change
1					
2	**General Plant**				
3					
4	389	Land & Land Rights	$2,033	$2,031	-0.10%
5	390	Structures & Improvements	77,681	77,583	-0.13%
6	391	Office Furniture & Equipment	331,492	337,250	1.74%
7	392	Transportation Equipment	646,456	645,487	-0.15%
8	393	Stores Equipment	20,667	20,667	
9	394	Tools, Shop & Garage Equipment	370,444	369,342	-0.30%
10	395	Laboratory Equipment	276,414	276,236	-0.06%
11	396	Power Operated Equipment	1,543,361	1,402,813	-9.11%
12	397	Communication Equipment	595,789	630,779	5.87%
13	398	Miscellaneous Equipment	31,732	31,672	-0.19%
14	399	Other Tangible Property			
15					
16	**TOTAL General Plant**		$3,896,069	$3,793,860	-2.62%
17					
18	**Common Plant**				
19					
20	389	Land & Land Rights	$195,578	$192,432	-1.61%
21	390	Structures & Improvements	3,274,250	3,205,062	-2.11%
22	391	Office Furniture & Equipment	1,746,483	1,750,775	0.25%
23	392	Transportation Equipment	624,056	667,975	7.04%
24	393	Stores Equipment	17,277	11,797	-31.72%
25	394	Tools, Shop & Garage Equipment	151,752	153,357	1.06%
26	395	Laboratory Equipment			
27	396	Power Operated Equipment			
28	397	Communication Equipment	477,189	480,912	0.78%
29	398	Miscellaneous Equipment	68,607	70,913	3.36%
30	399	Other Tangible Property			
31					
32	**TOTAL Common Plant**		$6,555,192	$6,533,223	-0.34%
33					
34					
35	**TOTAL Electric Plant in Service**		$123,946,514	$125,486,778	1.24%

MONTANA DEPRECIATION SUMMARY

Year: 1999

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production 1/	$62,067,429	$37,041,329	$38,489,606	4.07%
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production	2,315,980	1,709,837	1,726,801	2.41%
6	Transmission	24,512,970	12,503,994	12,938,994	2.38%
7	Distribution	29,355,883	14,225,986	15,017,354	3.28%
8	General	4,495,848	2,117,223	2,070,399	4.40%
9	Common	8,021,743	3,042,888	3,212,013	4.21%
10	**TOTAL**	$130,769,853	$70,641,257	$73,455,167	3.57%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account		Last Year Bal.	This Year Bal.	%Change
1					
2	151	Fuel Stock	$531,116	$544,763	2.57%
3	152	Fuel Stock Expenses Undistributed			
4	153	Residuals			
5	154	Plant Materials & Operating Supplies:			
6		Assigned to Construction (Estimated)			
7		Assigned to Operations & Maintenance			
8		Production Plant (Estimated)	540,157	534,970	-0.96%
9		Transmission Plant (Estimated)	227,242	221,888	-2.36%
10		Distribution Plant (Estimated)	261,985	265,725	1.43%
11		Assigned to Other			
12	155	Merchandise			
13	156	Other Materials & Supplies			
14	157	Nuclear Materials Held for Sale			
15	163	Stores Expense Undistributed			
16					
17	**TOTAL Materials & Supplies**		$1,560,500	$1,567,346	0.44%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	86.5.28			
2	Order Number	5219b			
3					
4	Common Equity		35.548%	12.300%	4.372%
5	Preferred Stock		11.280%	9.019%	1.017%
6	Long Term Debt - First Mortgage Bonds		44.491%	10.232%	4.552%
7	Other Long Term Debt		8.681%	8.222%	0.714%
8	**TOTAL**		100.000%		10.655%
9					
10	Actual at Year End				
11					
12	Common Equity		42.269%	12.300%	5.199%
13	Preferred Stock		4.186%	4.636%	0.194%
14	Long Term Debt		53.545%	9.209%	4.931%
15	Other				
16	**TOTAL**		100.000%		10.324%

1/ Includes deferred AFUDC, depreciation and interest on Coyote and acquisition adjustment.

STATEMENT OF CASH FLOWS

Year: 1999

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$34,106,960	$84,079,784	146.52%
5	Depreciation	25,278,905	25,724,554	1.76%
6	Amortization	527,498	1,621,351	207.37%
7	Deferred Income Taxes - Net	(3,086,777)	846,736	-127.43%
8	Investment Tax Credit Adjustments - Net	(974,672)	(888,062)	-8.89%
9	Change in Operating Receivables - Net	462,570	(8,094,643)	-1849.93%
10	Change in Materials, Supplies & Inventories - Net	271,007	(970,731)	-458.19%
11	Change in Operating Payables & Accrued Liabilities - Net	1,248,453	1,771,633	41.91%
12	Change in Other Regulatory Assets	702,737	563,557	-19.81%
13	Change in Other Regulatory Liabilities	289,604	(4,442,433)	-1633.97%
14	Allowance for Funds Used During Construction (AFUDC)	(199,488)	(419,934)	110.51%
15	Change in Other Assets & Liabilities - Net	(23,158,807)	11,911,018	-151.43%
16	Less Undistributed Earnings from Subsidiary Companies	(15,920,717)	(64,143,724)	302.89%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$19,547,273	$47,559,106	143.30%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($22,361,401)	($28,075,022)	25.55%
23	Acquisition of Other Noncurrent Assets	(15,283,378)	401,633	-102.63%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(175,311,592)	(80,704,819)	-53.96%
26	Contributions and Advances from Affiliates	26,063,100	28,591,800	9.70%
27	Disposition of Investments in and Advances to Affiliates	2,000,000	2,000,000	
28	Other Investing Activities: Depreciation on Nonutility Plant	2,222	8,465	280.96%
29	**Net Cash Provided by/(Used in) Investing Activities**	($184,891,049)	($77,777,943)	-57.93%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt	$37,000,000	$0	-100.00%
34	Preferred Stock			
35	Common Stock	175,311,616	80,704,795	-53.96%
36	Other:			
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper	15,000,000	0	-100.00%
39	Payment for Retirement of:			
40	Long-Term Debt	(20,300,000)	(300,000)	-98.52%
41	Preferred Stock	(100,000)	(100,000)	0.00%
42	Common Stock			
43	Other:			
44	Net Decrease in Short-Term Debt		(2,000,000)	
45	Dividends on Preferred Stock	(776,808)	(771,708)	-0.66%
46	Dividends on Common Stock	(40,469,690)	(45,321,381)	11.99%
47	Other Financing Activities (explained on attached page)			
48	**Net Cash Provided by (Used in) Financing Activities**	$165,665,118	$32,211,706	-80.56%
49				
50	**Net Increase/(Decrease) in Cash and Cash Equivalents**	$321,342	$1,992,869	520.17%
51	**Cash and Cash Equivalents at Beginning of Year**	$6,154,239	$6,475,581	5.22%
52	**Cash and Cash Equivalents at End of Year**	$6,475,581	$8,468,450	30.78%

LONG TERM DEBT

Year: 1999

	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	3,100,000	6.20%	203,236	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	$133,950,000		$11,946,678	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 available under revolving lines of credit, of which $40 million was outstanding at year end.
The average 1999 term loan rate was 6.683%.

PREFERRED STOCK

Year: 1999

	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%	1,600,000	84,560	5.29%
4										
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22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**					$19,947,548		$16,600,000	$769,560	4.64%

1/ Plus accrued dividends.

Company Name: Montana-Dakota Utilities Co. SCHEDULE 26

COMMON STOCK

Year: 1999

		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	53,137,304	$10.50						
5									
6	February	53,146,476	10.35						
7									
8	March	53,156,004	10.46	$0.24	$0.2000	16.67%	$27.19	$21.25	42.2 X 3/
9									
10	April	53,156,004	10.52						
11									
12	May	56,156,004	9.89						
13									
14	June	54,054,107	10.74	0.33	0.2000	39.39%	24.38	20.31	23.5 X 4/
15									
16	July	54,054,107	10.88						
17									
18	August	54,570,768	10.93						
19									
20	September	56,665,283	11.48	0.53	0.2100	60.38%	24.75	22.38	20.8 X 4/
21									
22	October	56,665,283	11.66						
23									
24	November	57,038,394	11.62						
25									
26	December	57,038,394	11.74	0.43	0.2100	51.16%	24.38	18.81	13.2 X
27									
28									
29									
30	TOTAL Year End	57,038,394	$11.74	$1.53	$0.8200	46.41%			13.2 X

1/ Basic earnings per share.
2/ Calculated on 12 months ended using closing stock price.
3/ Reflects $39.9 million in noncash after-tax write-downs of oil and natural gas properties in 1998.
4/ Reflects $19.9 million in noncash after-tax write-downs of oil and natural gas properties in December 1998.

MONTANA EARNED RATE OF RETURN

Year: 1999

		Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service 1/	$126,950,566	$128,322,379	1.08%
3	108	(Less) Accumulated Depreciation 2/	69,416,357	72,157,815	3.95%
4					
5		**NET Plant in Service**	$57,534,209	$56,164,564	-2.38%
6					
7		CWIP in Service Pending Reclassification	$150,655	$806,928	435.61%
8					
9		Additions			
10	151	Fuel Stocks	$531,116	$544,763	2.57%
11	154, 156	Materials & Supplies	1,029,384	1,022,583	-0.66%
12	165	Prepayments	131,881	91,911	-30.31%
13		Other Additions			
14					
15		**TOTAL Additions**	$1,692,381	$1,659,257	-1.96%
16					
17		Deductions			
18	190	Accumulated Deferred Income Taxes	$12,808,506	$12,408,758	-3.12%
19	252	Customer Advances for Construction	30,931	965,637	3021.91%
20	255	Accumulated Def. Investment Tax Credits	1,128,592	193,730	-82.83%
21		Other Deductions			
22					
23		**TOTAL Deductions**	$13,968,029	$13,568,125	-2.86%
24		**TOTAL Rate Base**	$45,409,216	$45,062,624	-0.76%
25					
26		**Net Earnings**	$4,502,677	$5,122,579	13.77%
27					
28		**Rate of Return on Average Rate Base**	9.82%	11.32%	15.27%
29					
30		**Rate of Return on Average Equity**	11.46%	14.66%	27.92%
31					
32		Major Normalizing Adjustments & Commission			
33		Ratemaking adjustments to Utility Operations 3/			
34					
35		Adjustment to Operating Revenues			
36		Late Payment Revenues	$13,097	$17,493	33.56%
37		Average Pool Sales		(802,142)	
38					
39		Adjustment to Operating Expenses			
40		Elimination of Promotional & Institutional Advertising	(6,897)	(8,834)	28.08%
41					
42		Total Adjustments to Operating Income	$19,994	($775,815)	-3980.24%
43					
44					
45		**Adjusted Rate of Return on Average Rate Base**	9.86%	9.61%	-2.54%
46					
47		**Adjusted Rate of Return on Average Equity**	11.56%	10.61%	-8.22%

1/ Excludes Acquisition Adjustment of $2,498,788 for 1998 and $2,447,474 for 1999.
2/ Excludes Acquisition Adjustment of $1,224,900 for 1998 and $1,297,352 for 1999.
3/ Updated amounts, net of taxes.

MONTANA COMPOSITE STATISTICS

Year: 1999

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$90,786
5	107	Construction Work in Progress	516
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	1,023
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	72,158
11	252	Contributions in Aid of Construction	966
12			
13		**NET BOOK COSTS**	$19,201
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	$34,748
18			
19	403 - 407	Depreciation & Amortization Expenses	$4,664
20		Federal & State Income Taxes	2,161
21		Other Taxes	2,529
22		Other Operating Expenses	20,271
23		TOTAL Operating Expenses	$29,625
24			
25		Net Operating Income	$5,123
26			
27	415-421.1	Other Income	366
28	421.2-426.5	Other Deductions	539
29			
30		**NET INCOME**	$4,950
31			
32		Customers (Intrastate Only) 1/	
33			
34		Year End Average:	
35		Residential	19,063
36		Small General	4,855
37		Large General	263
38		Other	2,370
39			
40		**TOTAL NUMBER OF CUSTOMERS**	26,551
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	7,206
45		Average Annual Residential Cost per (Kwh) (Cents) *	$0.075
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	$44.63
48		Gross Plant per Customer	$3,419

1/ Reflects bills divided by twelve.

MONTANA CUSTOMER INFORMATION

Year: 1999

	City/Town	Population (Include Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Antelope	130	53	12	3	68
2	Bainville	165	86	32	6	124
3	Baker	1,818	905	292	8	1,205
4	Brockton	365	93	28	2	123
5	Carlyle	20	1	3		4
6	Culbertson	796	361	122	3	486
7	Fallon	235	171	83	1	255
8	Fairview	869	382	82	2	466
9	Flaxville	88	66	20	2	88
10	Forsyth	2,178	1,046	263	2	1,311
11	Froid	195	135	44	2	181
12	Glendive	4,802	3,248	746	4	3,998
13	Homestead	50	21	9	1	31
14	Ismay	19	22	14	1	37
15	Medicine Lake	357	171	45	4	220
16	Miles City	8,461	4,488	911	13	5,412
17	Outlook	109	62	24	2	88
18	Outlook Oil Field	Not Available		4	11	15
19	Plentywood	2,136	1,003	260	3	1,266
20	Plevna	140	99	30	2	131
21	Poplar	881	919	172	3	1,094
22	Poplar Oil Field	Not Available		4	10	14
23	Redstone	70	24	17	1	42
24	Reserve	75	29	10	3	42
25	Rosebud	170	76	39	1	116
26	Savage	300	137	26	2	165
27	Scobey	1,154	606	169	3	778
28	Sidney	5,217	2,262	471	11	2,744
29	Terry	659	351	113	2	466
30	Whitetail	100	34	10	1	45
31	Wibaux	628	305	96	2	403
32	Wolf Point	2,880	1,524	316	2	1,842
33	Kinsey	20	105	35	2	142
34	MT Oil Fields	Not Available	6	34	70	110
35						
36	**TOTAL Montana Customers**	35,087	18,791	4,536	185	23,512

1/ 1990 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 1999

	Department	Year Beginning	Year End	Average
1	Electric	26	24	25
2	Gas	42 (1)	40 (2)	41 (2)
3	Accounting	29	25 (1)	27
4	Marketing/Communications	2	3	3
5	Management	7	7	7
6	Power	27	24	25
7	Service 2/	55 (5)	55 (5)	55 (5)
8				
9				
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41				
42	**TOTAL Montana Employees**	188 (6)	178 (8)	183 (7)

1/ Parentheses denotes part-time.
2/ Reflects service employees such as meter readers, service dispatchers and servicemen.

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2000

	Project Description	Total Company	Total Montana	
1	Projects>$1,000,000	$0	$0	
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12	Other Projects<$1,000,000			
13				
14	Electric			
15	Production	$4,236,344	$998,421	1/
16	Transmission:			
17	Integrated	610,454	116,832	1/
18	Direct	850,508	48,658	2/
19	Distribution	5,174,256	772,923	2/
20	General	1,441,190	559,588	2/
22	Common:			
23	General Office	1,458,042	330,881	1/
24	Other Direct	1,071,748	247,045	2/
25	Total Electric	$14,842,542	$3,074,348	
26				
27	Gas			
28	Distribution	$5,559,803	$1,993,685	2/
29	General	3,343,444	514,938	2/
30	Common:			
31	General Office	806,233	237,292	1/
32	Other Direct	532,671	184,268	2/
33	Total Gas	$10,242,151	$2,930,184	
34				
35				
36				
37				
38				
39				
40				
41				
42				
43	TOTAL	$25,084,693	$6,004,531	

1/ Allocated to Montana.

2/ Directly assigned to Montana.

TOTAL INTEGRATED SYSTEM & MONTANA PEAK AND ENERGY

Year: 1999

Integrated System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	6	1900	336.5	274,064	80,306
2	Feb.	10	2000	291.4	234,815	78,158
3	Mar.	8	1100	282.8	276,631	110,119
4	Apr.	1	1200	285.6	248,526	92,440
5	May	28	1700	282.6	244,144	87,283
6	Jun.	21	1800	354.3	228,737	68,950
7	Jul.	28	1700	420.6	258,258	66,689
8	Aug.	26	1800	393.3	249,122	61,203
9	Sep.	22	1800	270.0	211,203	59,340
10	Oct.	28	900	262.3	233,974	72,200
11	Nov.	29	1900	300.6	241,143	83,644
12	Dec.	20	1900	342.4	267,415	83,188
13	**TOTAL**				2,968,032	943,520

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.	6	1900	80.4		
15	Feb.	10	2000	76.6		
16	Mar.	8	1100	68.7		
17	Apr.	1	1200	65.2		
18	May	28	1700	70.7		
19	Jun.	21	1800	83.9		
20	Jul.	28	1700	96.8	Not Available	Not Available
21	Aug.	26	1800	90.2		
22	Sep.	22	1800	65.6		
23	Oct.	28	900	62.6		
24	Nov.	29	1900	76.0		
25	Dec.	20	1900	83.6		
26	**TOTAL**					

TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	2,334,486	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	2,075,446
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	16,283	for Resale	
7	(Less) Energy for Pumping			
8	**NET Generation**	2,350,769	Non-Requirements Sales	
9	Purchases	859,652	for Resale	943,520
10	Power Exchanges			
11	Received	3,540	Energy Furnished	
12	Delivered	42,650	Without Charge	24
13	**NET Exchanges**	(39,110)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	1,015,462	Electric Utility	5,706
16	Delivered	956,182		
17	**NET Transmission Wheeling**	59,280	Total Energy Losses	178,849
18	Transmission by Others Losses	(27,046)		
19	**TOTAL**	3,203,545	**TOTAL**	3,203,545

Montana-Dakota's annual peak occurred during HE1700 July 28, 1999. All generation units were available for operation durning the peak hour. The following units were on line and providing energy.

Heskett #1	21.7
Heskett #2	68.3
Lewis & Clark	36.5
Glendive Turbine	25.2
Miles City Turbine	17.2
Coyote	95.0
Big Stone	100.0

In addition to the above units, Montana-Dakota was purchasing 67 MW of its 67 MW share of the Antelope Valley 2 unit. Montana-Dakota also purchased 50 MW and sold 101 MW from and to other MAPP utilities with the remaining amount needed to meet the peak demand.

SOURCES OF ELECTRIC SUPPLY

Year: 1999

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Combustion Turbine	Williston Plant	Williston, ND	10.6	75.7
2	Combustion Turbine	Miles City Turbine	Miles City, MT	28.9	4,082.0
3	Thermal	Lewis & Clark Station	Sidney, MT	44.4	226,664.0
4	Combustion Turbine	Glendive Turbine	Glendive, MT	42.3	12,126.0
5	Thermal	Heskett Station	Mandan, ND	103.0	527,121.0
6	Thermal	Big Stone Station	Milbank, SD	107.5	828,897.0
7				(MDU SHARE)	
8	Thermal	Coyote Station	Beulah, ND	107.0	752,863.0
9				(MDU SHARE)	
10	Purchases	Basin Electric	10-31-2006	66.4	510,497.0
11					
12					
13					
14					
15					
16					
17					
18					
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38					
39					
40					
41					
42					
43	**Total**			510.1	2,862,325.7

Outage Start Date	Brief Description of Primary Cause	Outage Duration (hrs.)
	Big Stone Plant	
1/12/99	Master Fuel Trip	4.68
4/3/99	Boiler Tube Leak	23.35
4/9/99	Boiler Tube Leak	25.75
5/28/99	Remove Duct Blanks	22.72
6/15/99	Boiler Tube Leak	27.35
7/6/99	Boiler Tube Leak	34.88
8/9/99	Boiler Master Fuel Trip	3.50
8/9/99	Boiler Master Fuel Trip	1.30
8/10/99	Boiler Master Fuel Trip	25.10
8/21/99	Boiler Master Fuel Trip	6.02
8/22/99	Boiler Master Fuel Trip	1.57
9/10/99	Boiler Water Wash	135.63
9/22/99	Boiler Tube Leak	49.45
9/25/99	Boiler Tube Leak	15.93
	Coyote Station	
1/7/99	Boiler Master Fuel Trip	1.57
1/18/99	Boiler Tube Leak	29.50
2/4/99	Boiler Water Wash	69.43
2/14/99	Turbine Balance	7.35
6/10/99	Boiler Water Wash	103.18
8/6/99	Boiler Tube Leak	46.38
11/10/99	Boiler Water Wash	100.55
11/25/99	Boiler Tube Leak	79.87
12/11/99	Boiler Master Fuel Trip	3.17
12/30/99	Low Pressure Turbine Blade Failure	18.60
	Heskett Unit 1*	
1/1/99	Excitor failure	91.97
1/5/99	Turbine Extraction Leak	5.47
1/8/99	Feedwater Line Leak	15.67
4/19/99	Solinoid Turbine Trip	2.83
6/11/99	Maintenance Outage	231.78
9/25/99	Grate Repair	37.17
11/29/99	Boiler Tube Leak	49.73
	Heskett Unit 2*	
2/18/99	Maintenance outage	103.45
6/3/99	Maintenance outage	112.38
6/8/99	Boiler Tube Leak	29.13
9/14/99	Boiler Tube Leak	88.05
11/4/99	Boiler Tube Leak	179.08
	Lewis & Clark Station*	
2/24/99	Scrubber Trip	1.08
3/16/99	Air Heater Problems	4.90
4/16/99	Controls Upgrade	541.88
6/11/99	Turbine Maintenance	935.28
7/22/99	Boiler Trip	3.22
7/23/99	Clean scrubber	8.33
7/23/99	Boiler Trip	2.56
7/24/99	Boiler Trip	4.63
7/24/99	Boiler Trip	1.90
7/25/99	Boiler Trip	1.30
7/25/99	Boiler Trip	1.30
8/1/99	Turbine Maintenance	13.58
8/11/99	Boiler Trip	4.93
9/9/99	Scrubber Inspection	9.50
9/25/99	Boiler Trip	1.11
11/2/99	Substation Protective Relay Trip	7.11
11/17/99	Boiler Trip	2.86

* Outages Other Than Reserve Shutdowns for Economic Dispatch

Company Name: Montana-Dakota Utilities Co. SCHEDULE 35

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 1999

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1							
2	NONE						
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
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24							
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26							
27							
28							
29							
30							
31							
32	**TOTAL**						

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 36

MONTANA CONSUMPTION AND REVENUES

Year: 1999

	Sales of Electricity	Operating Revenues Current Year	Operating Revenues Previous Year	MegaWatt Hours Sold Current Year	MegaWatt Hours Sold Previous Year	Avg. No. of Customers 1/ Current Year	Avg. No. of Customers 1/ Previous Year
1	Residential	$10,210,220	$10,502,131	137,371	141,670	19,063	19,084
2	Small General	5,851,206	6,043,309	94,370	97,577	4,855	4,812
3	Large General	11,458,498	11,004,984	251,014	237,253	263	259
4	Lighting	674,014	672,513	9,688	9,691	2,262	2,340
5	Municipal Pumping	318,833	324,447	7,037	7,162	108	105
6	Sales to Other Utilities	5,375,379	3,182,031	Not Applicable	Not Applicable	Not Applicable	Not Applicable
7							
8							
9							
10							
11							
12							
13	**TOTAL**	$33,888,150	$31,729,415	499,480	493,353	26,551	26,600

1/ Reflects bills divided by twelve.