YEAR 2003

ANNUAL REPORT
OF

NorthWestern Energy

GAS UTILITY

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

REVISED JULY 28, 1998

NATURAL GAS ANNUAL REPORT

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Sch. 1

IDENTIFICATION

Legal Name of Respondent:	NorthWestern Corporation (formerly The Montana Power Company)
Name Under Which Respondent Does Business:	NorthWestern Energy
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	Patrick Corcoran
Telephone Number for Report Inquiries:	(406) 497-2202
Address for Correspondence Concerning Report:	40 East Broadway Street Butte, MT 59701

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity.

NorthWestern Energy is a 100% controlled division of:

NorthWestern Corporation
125 South Dakota Avenue
Sioux Falls, SD 57104-6403

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	NOT APPLICABLE	
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Sch. 3

OFFICERS

Title	Department Supervised	Name
President & Chief Executive Officer	Executive	Gary G. Drook
Chief Operating Officer	Operations	Michael J. Hansen
Vice President, Human Resources & Communications	Human Resources Communications Benefits & Compensation	Roger Schrum
Chief Financial Officer	Tax, Accounting Operations, Financial Planning & Analysis	Brian Bird
Vice President Information Technology	IT Applications & Infastructure Systems Continuity Licensing & Leasing Telecommunications	Bart Thielbar
Vice President Administration	Government Relations State, Local & Community Relations	Dennis Lopach
Vice President, Distribution Operations	Distribution Services Distribution Engineering & Performance SD Construction & Maintenance	Curt Pohl
Vice President, Transmission Operations	Transmission Contracts & Scheduling Electric & Gas Transmission & Storage General Production & Generation Transmission Operations & Regional Issues	David G. Gates
Vice President, Regulatory Affairs & Support Services	Regulatory Affairs Electric & Natural Gas Supply	Patrick R. Corcoran
Vice President, Asset Management	Asset Management Safety/Health/Environmental Process Improvement	Greg Trandem
Vice President, Customer Care	Revenue Collections Customer Strategies Call Center Systems Infastructure & Support Customer/Supplier Relations	Bobbi Schroeppel
Vice President, Legal Administration	Legal	Alan Dietrich
Vice President, Deputy General Counsel	Legal	Thomas J. Knapp
Vice President, General Counsel & CLO	Legal	Eric Jacobsen
Vice President, Audit & Controls	Internal Audit Project Office	Maurice Worsfold
Chief Restructuring Officer		William M. Austin
Chief Accountant	Financial Reporting	Kendall Kliewer

Sch. 4	CORPORATE STRUCTURE - 1/			
	Subsidiary/Company Name	Line of Business	Earnings (000)	% of Total
1				
2	**NORTHWESTERN ENERGY**			
3				
3	**Utility Operations**		37,657	110.74%
4	Electric Utility	Electric utility		
5	Natural Gas Utility	Natural gas utility		
6	Propane Utility	Propane utility		
7	Canadian-Montana Pipe Line Corporation	Natural gas transmission		
8	Montana Power Capital 1	Financing		
9	MPC Natural Gas Funding Trust	Bond transition financing		
10				
11	**Nonutility Operations**		(3,651)	-10.74%
12	Montana Power Services Company	Inactive		
13	Northwestern Energy Marketing	Supply energy to schools and public lighting		
14	One Call Locators, Ltd. 1/	Underground facility locating		
15	Colstrip Unit 4 Lease Mgmt Division	Wholesale sales of electric power *		
16	Clark Fork and Blackfoot L.L.C.	Milltown Dam		
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54	**TOTAL**		34,005	100.00%
55	1/ One Call Locators, Ltd was sold in June 2003.			
56				
57				
58	* Colstrip Unit 4 Lease Management Division is an operating division of Northwestern Energy.			

Sch. 5

CORPORATE ALLOCATIONS

	Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
1 2	Corporate - 1/	Includes all of the Corporate Departments in NOR including Chariman; Vice Chairman; CFO; HR; Flight Services & Investor Services.	Direct Charge of a Fixed Monthly Amount from corporate	$3,742,796	45.28%	$4,523,200
3	Utility Administration - 2/					
4 5 6 7 8 9 10 11 12	Executive Department	Includes the following departments: CEO; T&D Executives; Asset Mgmt; Market Analysis & Planning.	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	$1,606,958	69.08%	$719,112
13 14 15 16 17 18 19	Human Resources	Includes the following departments: Human Resources; Benefits Admin.; Compensation & Labor Relations; Employment; Organizational Development; Technology Training;	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	1,613,173	68.94%	726,795
20 21 22 23 24 25 26 27 28	Finance / Accounting	Includes the following departments: Audit Services; Risk Management; Treasury Services; Accounting; Tax & Financial Reporting Credit & Cash Management	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	6,545,705	64.05%	3,673,618
29 30 31 32 33 34 35	MT Facilities	Includes the following departments: Facilities; Mailing Services & Printing Services	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	2,035,980	62.65%	1,213,819

Sch. 5 cont.

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Information Services	Includes the following departments: IT Sr; VP/CIO; IT Applications; Administrative Systems; Special Purpose Systems; Client Services; Infrastructure; Technical Services; Architecture and Key Accounts Rep	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on %'s developed using formulas based on net plant, revenues and gross payroll.	6,854,591	68.94%	3,088,245
Administrative Services	Sr. VP of Administrative Service; Legal; Government Affairs; Records Control	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on %'s developed using formulas based on net plant, revenues and gross payroll.	3,663,420	84.09%	693,323
Customer Service	Customer Service; Promotional Advertising	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	12,791,894	72.35%	4,889,082
Communications	Communications; Advertising; Community Relations; Web Development; Video/Photo Services.	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	851,971	68.77%	386,832
TOTAL			$39,706,488	66.60%	$19,914,026

1/ -Corporate Departments are located in Sioux Falls and a set amount was charged to the utility companies for the year.

2/ - Utility administration departments are in transition with many areas within N.W.E being combined.
Cost were charged direct to MT & SD/NE utilities and then allocated to the segments during most of the year.

Company Name: SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year:

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	Nonutility Subsidiaries					
2						
3	One Call Locators *	Line location services	Market Rates	655,513	0.83%	655,513
4						
5						
6	Colstrip Unit 4 - Lease Management Division	Purchased Power	Market Rates	159,571	0.20%	159,571
7						
8						
31						
32	TOTAL Nonutility Subs			815,084		815,084
33	Total Nonutility Subs Revenues			79,286,081		
34						
35	Utility Subsidiaries					
36	Total Utility Subsidiaries					
37	Total Utility Sub Revenues			3,757,415		
38	TOTAL AFFILIATE TRANSACTIONS			815,084		815,084

* The sale of One Call Locators by the company was completed in June 2003.

Sch. 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3	One Call Locators *	Sales of Gas & Electricity	Tariff Schedules	$4,016	0.03%	$4,016
4						
5						
6						0
7						0
8						0
9	**Total Nonutility Subsidiaries**			4,016	0.03%	4,016
10	**Total Nonutility Subsidiaries Expenses**			13,761,836		
11						
12						
13	**Utility Subsidiaries**					
14						-
15	**Total Utility Subsidiaries**			-	0.00%	-
16	**Total Utility Subsidiaries Expenses**			72,466,962		
17	**TOTAL AFFILIATE TRANSACTIONS**			$4,016		$4,016

* The sale of One Call Locators by the company was completed during June 2003

Sch. 8	MONTANA UTILITY INCOME STATEMENT - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
400	Operating Revenues	$177,868,109	-	$177,868,109	$ 118,014,893	50.72%
Total Operating Revenues		177,868,109	-	177,868,109	118,014,893	50.72%
	Operating Expenses					
401	Operation Expense	116,630,629	(4,087,360)	120,717,989	54,286,758	114.84%
402	Maintenance Expense	3,991,305	-	3,991,305	5,015,368	-20.42%
403	Depreciation Expense	10,593,894	-	10,593,894	9,897,476	7.04%
404-405	Amort. & Depletion of Gas Plant	1,192,524	-	1,192,524	989,920	20.47%
406	Amort. of Plant Acquisition Adj.	(2,288,552)	(2,288,552)			
408.1	Taxes Other Than Income Taxes	15,937,102	-	15,937,102	14,651,142	8.78%
409.1	Income Taxes-Federal	(5,604,550)	2,148,563	(7,753,113)	(1,090,728)	>-300.00%
	-Other	403,623	444,360	(40,737)	198,081	103.77%
410.1	Deferred Income Taxes-Dr.	14,280,376	-	14,280,376	3,104,219	>300.00%
411.1	Deferred Income Taxes-Cr.	(1,801,127)	-	(1,801,127)	3,435,907	-152.42%
411.4	Investment Tax Credit Adj.	(1)	-	(1)	103	-100.97%
Total Operating Expenses		153,335,223	(3,782,989)	157,118,212	90,488,246	69.45%
NET OPERATING INCOME		$ 24,532,886	$ 3,782,989	$ 20,749,897	$ 27,526,647	-10.88%

The financial results reported include income taxes that are based upon NorthWestern's tax basis for plant assets purchased from the Montana Power Company. This tax basis differs from amounts included in the most recently decided rate proceeding and results in a lower deferred tax credit. This change was made in order to prevent any possible violation of the normalization requirements of the federal income tax code. The change results in an increase in the reported rate base.

Sch. 9	MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)		
Account Number & Title	This Year Cons. Utility	Last Year Cons. Utility	% Change
Core Distribution Business Units (DBUs)			
440 Residential	$ 86,467,860	$66,947,319	29.16%
442.1 Commercial	42,599,960	32,450,585	31.28%
442.2 Industrial Firm	1,463,246	1,080,745	35.39%
445 Public Authorities	284,199	96,983	193.04%
448 Interdepartmental Sales	331,872	270,611	22.64%
491.2 CNG Station	2,971	7,591	-60.86%
Total Sales to Core DBUs	131,150,108	100,853,834	30.04%
447 Sales for Resale 1/	31,652,646	883,100	>300.00%
Total Sales of Natural Gas	31,652,646	883,100	>300.00%
Transportation			
489 Transportation (inc. CMP)	12,301,297	12,639,325	-2.67%
495 Off System Storage	555,235	1,246,273	-55.45%
Total Revenues From Transportation	12,856,532	13,885,598	-7.41%
Other Operating Revenue			
Miscellaneous Revenues	2,208,823	2,392,361	-7.67%
Total Other Operating Revenue	2,208,823	2,392,361	-7.67%
TOTAL OPERATING REVENUE	177,868,109	118,014,893	50.72%

1/ In 2003, NorthWestern entered into approximately 3.3 bcf of fixed price natural gas contracts to hedge customer price risk during the 2003-2004 winter season. These fixed price contracts at the AECO hub systematically offset medium-term on-system supply, which are purchased from a third party on NorthWestern's system at a floating daily index price. Other sales were conducted due to excess supply on system or exchanges for in-ground storage from customers. All purchases and sales were conducted as regulated activity for the Montana customers and such net cost will be recovered in rates.

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Production Expenses**					
2	**Production & Gathering-Operation**					
3	750 Supervision & Engineering	$ -	$ -	$ -	$ -	-
4	751 Maps & Records	-	-	-	-	-
5	752 Gas Wells Expenses	-	-	-	-	-
6	753 Field Lines Expenses	-	-	-	-	-
7	754 Field Compressor Station Expense	-	-	-	-	-
8	755 Field Comp. Station Fuel & Power	-	-	-	-	-
9	756 Field Meas. & Reg. Station Expense	-	-	-	-	-
10	757 Dehydration Expense	-	-	-	-	-
11	758 Gas Well Royalties	-	-	-	-	-
12	759 Other Expenses	-	-	-	-	-
13	760 Rents	-	-	-	-	-
14	**Total Oper.-Production & Gathering**	-	-	-	-	-
15						
16	**Other Gas Supply Expense-Operation**					
17	800 NG Wellhead Purchases	116,252,316	-	116,252,316	49,566,256	134.54%
18	800 NG Wellhead Purchases, Intraco.	-	-	-	-	-
19	803 NG Transmission Line Purchases	352,438	-	352,438	675,660	-47.84%
20	805 Other Gas Purchases	(5,959,470)	-	(5,959,470)	(8,115,661)	26.57%
21	805 Purchased Gas Cost Adjustments	-	-	-	-	-
22	805 Incremental Gas Cost Adjustments	-	-	-	-	-
23	805 Deferred Gas Cost Adjustments	-	-	-	-	-
24	806 Exchange Gas	-	-	-	-	-
25	807 Well Expenses-Purchased Gas	260,125	-	260,125	18,446	>300.00%
26	807 Purch. Gas Meas. Stations-Oper.	-	-	-	-	-
27	807 Purch. Gas Meas. Stations-Maint.	-	-	-	-	-
28	807 Purch. Gas Calculations Expenses	-	-	-	-	-
29	808 Other Purchased Gas Expenses	-	-	-	-	-
30	808 Gas Withdrawn from Storage -Dr.	645,095	-	645,095	24,719,982	-97.39%
31	809 Gas Delivered to Storage -Cr.	(3,852)	-	(3,852)	(22,688,056)	99.98%
32	810 Gas Used-Comp. Station Fuel-Cr.	-	-	-	-	-
33	811 Gas Used-Products Extraction-Cr.	-	-	-	-	-
34	812 Gas Used-Other Utility Oper.-Cr.	-	-	-	-	-
35	813 Other Gas Supply Expenses	-	-	-	-	-
36	**Total Other Gas Supply Expenses**	111,546,652	-	111,546,652	44,176,627	152.50%
37	**Total Production Expenses**	111,546,652	-	111,546,652	44,176,627	152.50%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Storage Expenses**					
2						
3	**Underground Storage-Operation**					
4	814 Supervision & Engineering	94,128	-	94,128	51,366	83.25%
5	815 Maps & Records	496	-	496	1,165	-57.40%
6	816 Wells	148,613	-	148,613	121,465	22.35%
7	817 Lines	15,473	-	15,473	25,085	-38.32%
8	818 Compressor Station	291,228	-	291,228	245,495	18.63%
9	819 Compressor Station Fuel & Power	-	-	-	-	
10	820 Measuring & Regulating Station	29,926	-	29,926	19,895	50.42%
11	821 Purification	82,220	-	82,220	67,907	21.08%
12	824 Other Expenses	88,987	-	88,987	90,382	-1.54%
13	825 Storage Well Royalties	97,914	-	97,914	78,707	24.40%
14	826 Rents	-	-	-	39	-100.00%
15	**Total Operation-Underground Storage**	848,985	-	848,985	701,506	21.02%
16						
17	**Underground Storage-Maintenance**					
18	830 Supervision & Engineering	160	-	160	-	
19	831 Structures & Improvements	9,492	-	9,492	19,103	-50.31%
20	832 Reservoirs & Wells	1,242	-	1,242	2,370	-47.59%
21	833 Lines	21,001	-	21,001	12,099	73.58%
22	834 Compressor Station Equipment	188,640	-	188,640	103,329	82.56%
23	835 Meas. & Reg. Station Equipment	13,730	-	13,730	8,052	70.51%
24	836 Purification Equipment	8,043	-	8,043	12,471	-35.50%
25	837 Other Equipment	7,459	-	7,459	8,876	-15.97%
26	**Total Maintenance-Underground Storage**	249,767	-	249,767	166,300	50.19%
27	**Total Underground Storage Expenses**	1,098,752	-	1,098,752	867,806	26.61%
28	**Transmission Expenses**					
29	**Transmission-Operation**					
30	850 Supervision & Engineering	1,728,535	-	1,728,535	1,663,300	3.92%
31	851 System Control & Load Dispatching	503,645	-	503,645	417,410	20.66%
32	853 Compressor Station Labor & Expense	630,368	-	630,368	454,380	38.73%
33	855 Other Fuel & Power for Comp. Stat.	2	-	2	-	
34	856 Mains	499,503	-	499,503	442,865	12.79%
35	857 Measuring & Regulating Station	719,131	-	719,131	505,482	42.27%
36	858 Transmission & Comp.-By Others	-	-	-	115	-100.00%
37	859 Other Expenses	818,701	-	818,701	961,660	-14.87%
38	860 Rents	51	-	51	30	67.04%
39	**Total Operation-Transmission**	4,899,936	-	4,899,936	4,445,242	10.23%
40	**Transmission-Maintenance**					
41	861 Supervision & Engineering	-	-	-	-	
42	862 Structures & Improvements	480,258	-	480,258	385,148	24.69%
43	863 Mains	350,897	-	350,897	516,919	-32.12%
44	864 Compressor Station Equipment	342,079	-	342,079	370,828	-7.75%
45	865 Meas. & Reg. Station Equipment	219,348	-	219,348	336,177	-34.75%
46	867 Other Equipment	20,038	-	20,038	29,628	-32.37%
47	**Total Maintenance-Transmission**	1,412,620	-	1,412,620	1,638,700	-13.80%
48	**Total Transmission Expenses**	6,312,556	-	6,312,556	6,083,942	3.76%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Distribution Expenses**					
2	**Distribution-Operation**					
3	870 Supervision & Engineering	791,133	-	791,133	-	
4	871 Load Dispatching	-	-	-	515,690	-100.00%
5	872 Compressor Station Labor & Expense	-	-	-	319	-100.00%
6	873 Compressor Station Fuel and Power	-	-	-	-	-
7	874 Mains and Services	1,017,970	-	1,017,970	782,880	30.03%
8	875 Meas. & Reg. Station-General	11,220	-	11,220	12,713	-11.75%
9	876 Meas. & Reg. Station-Industrial	4,149	-	4,149	4,768	-12.97%
10	877 Meas. & Reg. Station-City Gate	26,556	-	26,556	23,000	15.46%
11	878 Meter & House Regulator	722,545	-	722,545	633,025	14.14%
12	879 Customer Installations	2,019,053	-	2,019,053	1,629,696	23.89%
13	880 Other Expenses	1,770,205	-	1,770,205	1,613,331	9.72%
14	881 Rents	16,059	-	16,059	14,946	7.45%
15	**Total Operation-Distribution**	6,378,890	-	6,378,890	5,230,368	21.96%
16	**Distribution-Maintenance**					
17	885 Supervision & Engineering	56,935	-	56,935	220,558	-74.19%
18	886 Structures & Improvements	2,227	-	2,227	7,475	-70.21%
19	887 Mains	634,380	-	634,380	501,998	26.37%
20	889 Meas. & Reg. Station Exp.-General	60,570	-	60,570	64,037	-5.41%
21	890 Meas. & Reg. Station Exp.-Industrial	150	-	150	2,060	-92.74%
22	891 Meas. & Reg. Station Exp.-City Gate	4,638	-	4,638	23,168	-79.98%
23	892 Services	272,095	-	272,095	342,374	-20.53%
24	893 Meters & House Regulators	157,310	-	157,310	170,121	-7.53%
25	894 Other Equipment	8,667	-	8,667	35,610	-75.66%
26	**Total Maintenance-Distribution**	1,196,970	-	1,196,970	1,367,401	-12.46%
27	**Total Distribution Expenses**	7,575,860	-	7,575,860	6,597,769	14.82%
28	**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**					
30	901 Supervision	-	-	-	-	-
31	902 Meter Reading	317,042	-	317,042	336,157	-5.69%
32	903 Customer Records & Collection	2,168,739	-	2,168,739	2,149,050	0.92%
33	904 Uncollectible Accounts	503,543	-	503,543	373,573	34.79%
34	905 Miscellaneous Customer Accounts	493	-	493	39	>300.00%
35	**Total Customer Accounts Expenses**	2,989,817	-	2,989,817	2,858,819	4.58%
36						
37	**Customer Service & Information Expenses**					
38	**Customer Service-Operation**					
39	907 Supervision	-	-	-	-	
40	908 Customer Assistance	953,665	-	953,665	819,966	16.31%
41	909 Inform. & Instructional Advertising	233,583	-	233,583	242,549	-3.70%
42	910 Misc. Customer Service & Inform.	-	-	-	475	-100.00%
43	**Total Customer Service & Information Exp.**	1,187,248	-	1,187,248	1,062,990	11.69%
44						
45	**Sales Expenses**					
46	**Sales-Operation**					
47	911 Supervision	381,774	-	381,774	85,630	>300.00%
48	912 Demonstrating & Selling	44,748	-	44,748	310,353	-85.58%
49	913 Advertising	44,884	-	44,884	145,210	-69.09%
50	916 Miscellaneous Sales	-	-	-	5,046	-100.00%
51	**Total Sales Expenses**	471,406	-	471,406	546,237	-13.70%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Administrative & General Expenses**					
2	**Admin. & General - Operation**					
3	407 Amortization of Regulatory Asset	(18,652,276)	-	(18,652,276)	(19,379,747)	3.75%
4	920 Administrative & General Salaries	6,603,170	-	6,603,170	8,509,704	-22.40%
5	921 Employee Travel	297,864	-	297,864	269,315	10.60%
6	921 Office Supplies & Expenses	890,206	-	890,206	1,480,475	-39.87%
7	922 Administrative Exp. Transferred-Cr.	(1,993,398)	-	(1,993,398)	(2,180,236)	8.57%
8	923 Outside Services Employed	2,077,231	-	2,077,231	1,966,550	5.63%
9	924 Property Insurance	170,940	-	170,940	233,493	-26.79%
10	925 Legal & Claim Department	(3,021,683)	(4,087,360)	1,065,677	1,267,588	>-300.00%
11	926 Employee Pensions & Benefits	119,120	-	119,120	808,880	-85.27%
12	928 Regulatory Commission Expenses	20,754	-	20,754	2,438	>300.00%
13	930 General Advertising	1,419	-	1,419	1,202	18.09%
14	930 Miscellaneous General Expenses	136,181	-	136,181	212,478	-35.91%
15	930 USBC Expenses	1,323,511	-	1,323,511	1,425,390	-7.15%
16	931 Rents	334,656	-	334,656	647,439	-48.31%
17	**Total Operation-Admin. & General**	(11,692,305)	(4,087,360)	(7,604,945)	(4,735,032)	-146.93%
18	**Admin. & General - Maintenance**					
19	935 General Plant	1,131,948	-	1,131,948	1,842,968	-38.58%
20	**Total Admin. & General Expenses**	(10,560,357)	(4,087,360)	(6,472,998)	(2,892,064)	-265.15%
21	**TOTAL OPER. & MAINT. EXPENSES**	$120,621,934	($4,087,360)	$124,709,294	59,302,126	103.40%
22						
23						
24						
25						
26						

Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)				
		Description	This Year	Last Year	% Change
1					
2		**Federal Taxes**			
3	2521xx	Social Security, Medicare and Unemployment	$1,081,039	$1,333,552	-18.94%
4					
5		**Montana Taxes**			
6	252410	Real Estate & Personal Property	13,965,792	12,567,989	11.12%
7	252213	Crow Tribe RR and Utility Tax	31,661	18,074	75.17%
8	252214	Blackfoot Possessoray Tax	303,403	316,457	-4.13%
9	252450	Consumer Counsel	104,378	113,944	-8.40%
10	252450	Public Service Commission	313,772	304,786	2.95%
11	252450	MT DOR Working Interest Withholding	117,117	-	-
12		Various	-	16,882	-100.00%
13					
14					
15					
16					
17		**Canadian Taxes**			
18		Ad Valorem	19,940	(20,542)	197.07%
19					
20					
21					
22					
23	**TOTAL TAXES OTHER THAN INCOME**		$15,937,102	$14,651,142	8.78%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	Asphlundh Tree Expert	Tree Trimming	1,406,688
2	Automotive Rentals	Fleet Management	4,056,619
3	Bill Field Trucking	Equipment Transportation	318,869
4	Browning, Kaleczyc, Berry & Hovan	Legal Services	549,471
5	Computer Associates	Maintenance	115,063
6	Davenport, Evans, Hurwitz & Smith	Legal Services	1,561,167
7	Express Services	Temporary Employment Services	241,688
8	Filenet Corporation	Maintenance	107,779
9	First Data Integrated Systems	Customer Service	157,838
10	Gibson, Dunn & Crutcher	Legal Services	845,384
11	Graves Law Offices	Legal Services	2,081,569
12	Independent Inspection Company	Electric Line Inspection	102,101
13	Itron, Inc.	Hardware/Software Maintenance	429,203
14	Kema-Xenergy	Energy Audit Programs & Services	1,419,372
15	Lands Energy consultants	Consulting	115,339
16	Lazard Freres & Co	Advisory Fees	1,078,978
17	Leonard, Street & Deinard	Professional Services	520,722
18	Lockton Companies	Insurance Brokerage & Claims Adminstration	588,820
19	March Engineering	Contractor	109,848
20	Morrison & Foerster	Legal Services	190,626
21	Nat'l Center for Appropriate Technology	Lab Testing	1,034,797
22	Northwest Energy Efficiency	Energy Services	532,403
23	Orcom Solutions	Programming & Implementation	2,653,286
24	PAR Electric Contractors	Contractor	1,287,768
25	Paul J. Evans	Consulting Services	344,960
26	Paul, Hastings, Janofsky & Wal	Legal Services	6,086,819
27	Paul, Weiss, Rifkind, & Wharton	Legal Services	150,000
28	Power Resource Managers	Power Scheduling & Dispatch	363,815
29	Risk Administration	Risk Administration Services	191,663
30	River Network	Consultants	101,417
31	Rod Tabbert Construction, Inc.	Contractor	213,932
32	Skadden, Arps, Slate, Meagh & Flom	Legal Services	434,952
33	Spiker Communication	Advertising	148,432
34	State Line Contractors	Contractor	245,456
35	Tony Laslovich	Contractor	106,536
36	Towers Perrin	Consulting/Actuary	283,058
37	Utilities Underground	Locator Services	101,766
38	Utility Consulting Services	Contractor	171,218
39	Varsity Contractors	Janitorial Services	197,477
40	Washington Group International	Consulting & Engineering	143,892
42	**Total of Payments Set Forth Above**		30,790,791

1/ Due to the multiple % allocations, it is not practical to separately identify amounts charged to the electric or gas utility. Consistent with prior years' presentations, this schedule contains payments of $100,000 or more.

Sch. 13

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

NorthWestern Energy does not make any contributions to Political Action Committees (PACs) or candidates.

There are two employee PACs, one called Citizens for Responsible Government / Employees of NorthWestern Energy, and one called NorthWestern Public Service Employee's Political Action Committee. These are organizations of employees and shareholders of NorthWestern Energy. All of the money contributed by members goes to support political candidates. No company funds may be spent in support of a political candidate. Nominal administrative costs for such things as duplicating and postage are paid by the company. These costs are charged to shareholder expense.

Sch. 14	PENSION COSTS			
	Description	Last Year	This Year	% Change
1	Plan Name: Retirement Plan for Employees			
2	of the Montana Power Company			
3	Defined Benefit Plan	Yes	Yes	
4	Defined Contribution Plan (See Schedule 14A)			
5	Is the Plan overfunded?	No - 3/	No - 3/	
6				
7				
8	Actuarial Cost Method			
9	IRS Code			
10	Annual Contribution by Employer	30,466	9,700,000	
11		-		
12	Accumulated Benefit Obligation	268,318,815	292,261,554	8.92%
13	Projected Benefit Obligation	275,899,175	300,852,204	9.04%
14	Fair Value of Plan Assets	163,468,246	188,693,229	15.43%
15				
16	Discount Rate for Benefit Obligations	6.50%	6.00%	
17	Expected Long-Term Return on Assets	8.50%	8.50%	
18				
19	Net Periodic Pension Cost:			
20	Service Cost	4,143,675	4,325,666	4.39%
21	Interest Cost	17,344,669	17,729,155	2.22%
22	Return on Plan Assets *(Expected)*	(16,474,650)	(13,419,317)	-18.55%
23	Net Amortization	1,919,570	1,919,570	0.00%
24	Recognized net actuarial loss	-	4,268,343	> 300.00%
25	Special Termination Benefit Charge	4,191,451		100.00%
26	Curtailment Charge	910,439		100.00%
27	Settlement Charge	3,744,292		100.00%
28	Total Net Periodic Pension Cost	15,779,446	14,823,417	-6.06%
29				
30	Minimum Required Contribution			
31	Actual Contribution	4,000,000	5,700,000	0.00%
32	Maximum Amount Deductible	20,535,023	54,597,991	0.00%
33	Benefit Payments	14,453,492	16,956,612	17.32%
34				
35	Montana Intrastate Costs:			
36	Pension Costs		NOT AVAILABLE	
37	Pension Costs Capitalized			
38	Accumulated Pension Asset (Liability) at Year End			
39				
40	Number of Company Employees : 1/			
41	Covered by the Plan			
42	Active	1,147	1,070	-6.71%
43	Retired	1,179	1,222	3.65%
44	Vested Former Employees (Deferred Inactive)	867	870	0.35%
45	Total Covered by the Plan	3,193	3,162	-0.97%
46	Total Not Covered by the Plan			
47				
48	1/ Obtained from The Actuarial Valuation Report of the Retirement Plan for Employees of The			
49	Montana Power Company, prepared as of January 1, 2002 and 2003 respectively.			
50				
51	2/ As of December 31, 2002, the fair value of assets was $163.5 million and the projected benefit obligation			
52	was $275.9 million. However, there was an unrecognized net loss of $77.9 million that has not been			
53	fully amortized pursuant to SFAS Statement No. 87. There is a pension liability of $7.3 million			
54	as of December 31, 2002.			
55				
56	3/ As of December 31, 2003, the fair value of assets was $188.7 million and the projected benefit obligation			
57	was $300.9 million. However, there was an unrecognized net loss of $74.5 million that has not been			
58	fully amortized pursuant to SFAS Statement No. 87. There is a pension liability of $12.4 million			
59	as of December 31, 2003.			
60				

Sch. 14A PENSION COSTS

	Description	Last Year	This Year	% Change
1	Plan Name: Retirement Savings Plan			
2				
3	Defined Benefit Plan (See Schedule 14)			
4	Defined Contribution Plan	Yes	Yes	
5	Is the Plan overfunded?			
6				
7				
8	Actuarial Cost Method			
9	IRS Code			
10	Annual Contribution by Employer			
11				
12	Accumulated Benefit Obligation			
13	Projected Benefit Obligation			
14	Fair Value of Plan Assets	85,938,422	103,986,249	21.00%
15				
16	Discount Rate for Benefit Obligations			
17	Expected Long-Term Return on Assets			
18				
19	Net Periodic Pension Cost:			
20	Service Cost			
21	Interest Cost		NOT APPLICABLE	
22	Return on Plan Assets (Actual)			
23	Net Amortization			
24	Total Net Periodic Pension Cost			
25				
26	Minimum Required Contribution			
27	Actual Contribution		NOT APPLICABLE	
28	Maximum Amount Deductible			
29	Benefit Payments			
30				
31	Montana Intrastate Costs:			
32	Pension Costs		NOT APPLICABLE	
33	Pension Costs Capitalized			
34	Accumulated Pension Asset (Liability) at Year End			
35				
36	Number of Company Employees :			
37	Covered by the Plan -- Eligible	1,048	1,015	-3.15%
38	Not Covered by the Plan	0	0	
39	Active -- Participating	1,029	1,005	-2.33%
40	Retired	0		
41	Vested Former Employees, Retirees and	377	355	-5.84%
42	Active-Noncontributing	0		
43	Total Covered by the Plan	1,141	1,015	-3.15%
44	Total Not Covered by the Plan	0	0	
45				
46				
47				
48				
49				
50				
51				
52				
53				
54				
55				

Sch 15	OTHER POST EMPLOYMENT BENEFITS (OPEBS)			
	Description	Last Year	This Year	% Change
1	**General Information**	1/	2/	
2	Discount Rate for Benefit Obligations	6.50%	6.50%	0.00%
3	Expected Long-Term Return on Assets	8.50%	8.50%	0.00%
4	Medical Cost Inflation Rate 3/	12.0%,5.0%:9	12.0%,5.0%:9	
5	Actuarial Cost Method	Projected Unit Credit Actuarial		
6		Cost Method allocated from date of hire to		
7		full eligibility date.		
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Total Company**			
15				
16	Accumulated Post Retirement Benefit Obligation (APBO)	36,196,701	46,434,906	28.28%
17	Fair Value of Plan Assets	4,869,343	5,433,986	11.60%
18				
19	List the amount funded through each funding method:			
20	VEBA - 6/	1,073,647	3,845,324	258.16%
21	401(h) - 6/	3,436,840	1,394,967	-59.41%
22	Other: Cash	1,071,468	402,710	-62.42%
23	Total Amount Funded	5,581,955	5,643,001	1.09%
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA	1,073,647	3,845,324	258.16%
27	401(h)	3,436,840	1,394,967	-59.41%
28	Other: Cash	1,071,468	402,710	-62.42%
29	Total Amount Tax Deductible	5,581,955	5,643,001	1.09%
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost	549,846	814,420	48.12%
33	Interest Cost	2,196,959	2,827,953	28.72%
34	Return on Plan Assets *(Expected)*	(399,122)	(261,309)	-34.53%
35	Amort. of Transition Oblig. & Regulatory Asset	788,960	788,960	0.00%
36	Amortization of Prior Service Cost	28,210	28,211	0.00%
37	Amortization of Gains or Losses	471,952	1,444,766	-96.42%
38	Curtailment charge	804,397	-	0.00%
39	Special Termination Benefit Charge	167,837	-	100.00%
40	Total Net Periodic Post Retirement Benefit Cost	4,609,039	5,643,001	100.00%
41	Benefit Cost Expensed	3,650,359	4,250,228	22.43%
42	Benefit Cost Capitalized	691,356	1,013,615	-72.23%
43	Benefit Cost Charged to MPC Subs & Colstrip Owners - 5/	267,324	379,158	-45.16%
44	Total Benefit Costs	4,609,039	5,643,001	41.83%
45	Benefit Payments	1,071,468	402,710	22.43%
46				-62.42%
47	Number of Company Employees :			
48	Covered by the Plans			
49	Active	1,147	1,070	-6.71%
50	Retired	986	1,034	4.87%
51	Retired Spouse/Dependents	68	71	4.41%
52	Total Covered by the Plans	2,201	2,175	-1.18%
53	Total Not Covered by the Plans	217	125	-42.40%

54 1/ Obtained from MPC's 2002 FASB 106 Valuation. Assumptions and data are as of December 31, 2002.
55 2/ Obtained from MPC's 2003 FASB 106 Valuation. Assumptions and data are as of December 31, 2003.
56 3/ First Year, Ultimate, Years to Reach Ultimate.

Sch 15A	OTHER POST EMPLOYMENT BENEFITS (OPEBS)			
	Description	Last Year	This Year	% Change
1	**General Information**	4/	4/	
2	Discount Rate for Benefit Obligations			
3	Expected Long-Term Return on Assets			
4	Medical Cost Inflation Rate 3/			
5	Actuarial Cost Method			
6				
7				
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Montana**	4/	4/	
15				
16	Accumulated Post Retirement Benefit Obligation (APBO)			
17	Fair Value of Plan Assets			
18				
19	List the amount funded through each funding method:			
20	VEBA			
21	401(h)			
22	Other: Cash			
23	Total Amount Funded			
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA			
27	401(h)			
28	Other: Cash			
29	Total Amount Tax Deductible			
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost			
33	Interest Cost			
34	Return on Plan Assets - Estimated			
35	Amort. of Transition Oblig. & Regulatory Asset			
36	Amortization of Gains or Losses			
37	Total Net Periodic Post Retirement Benefit Cost			
38	Benefit Cost Expensed			
39	Benefit Cost Capitalized			
40	Benefit Cost Charged to MPC Subs & Colstrip Owners			
41	Total Benefit Costs			
42	Benefit Payments			
43				
44	Number of Company Employees :			
45	Covered by the Plans			
46	Active			
47	Retired			
48	Retired Spouse/Dependents			
49	Total Covered by the Plans			
50	Total Not Covered by the Plans			
51	4/ Substantially all of the amounts are subject to the MPSC jurisdiction. Actual amounts that will be			
52	expensed, will reflect reductions for amounts billed to others or allocated to Yellowstone National Park.			
53	5/ Due to the sale of our generating assets, there is no longer billing to Colstrip owners from 2000 forward.			
54	6/ 2003 Trust funding was made on March 31, 2004 in the amounts of:			
55	($440,873) for 401(h) and $2,764,664 for VEBA.			

SCHEDULE 16

Note: This schedule includes the ten most highly compensated officers assigned or allocated to Montana that are not already included on Sch 17.

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary (Wages)	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	William Pascoe Vice President, Chief Operating Officer of Transmission (retired 2003)	44,615		4,624 B 478,731 C 5,748 D	533,718	182,729	192%
2	Ernie Kindt Vice President-Chief Accounting Officer (resigned 2003)	65,385		22,987 B 278,000 C 8,318 D	374,690	154,273	143%
3	Michael Manion Vice President-Legal Services (retired 2003)	26,615		1,538 A 7,701 B 296,098 C 3,303 D	335,255	187,594	79%
4	John Van Camp Vice President Organization and Staffing	248,926		15,226 D 14,000 F 3,745 I 5,779 J	287,676	276,270	4%
5	Richard Hylland President and Chief Operating Officer (resigned 2003)	209,656		53,942 B 10,892 D 2,595 H	277,085	747,968	-63%
6	Curtis Pohl Vice President-Distribution Operations	169,022		4,030 A 14,761 D 2,162 F 55,221 G	245,196	183,562	34%
7	Dennis Lopach Chief Administrative Officer	211,000		2,000 A 8,855 D 7,800 F	229,655	290,144	-21%
8	Gregory Trandem Vice President-Asset Management	184,917		5,460 A 15,603 D 3,892 F 11,966 H	221,838	340,387	-35%
9	Bart Thielbar Senior Vice President, Information Technology and Chief Information Officer	187,965		4,810 A 15,629 D 2,956 F	211,360	253,218	-17%
10	Kurt Whitesel Vice President-Controller and Treasurer (resigned 2003)	145,451		12,548 B 10,193 D 33,501 E	201,693	304,975	-34%

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation

1/ Bonuses paid in 2003 but earned in 2002 are not listed above due to the change in how we are reporting include the following: Curtis Pohl $116,294, Dennis Lopach $226,130, Gregory Trandem $164,993, and Bart Thielbar $146,569.

2/ All Other Compensation for named employees consists of the following:

A> Merit Cash

B> Vacation Sellbacks / Vacation Payout

C> Change in Control Payments

D>Employer Contributions to Benefits-Medical, Dental, Vision, EAP/Carewise, Term Life, Group Term Life, 401k

E> Severance Payment

F> Vehicle Payment / Car Allowance

G> Payment for Relocation Expenses

H> Imputed Income

I> Country Club Dues

J> Tax for Gross-up Pmts-SVIP Stk

**BONUSES ARE REPORTED IN THE YEAR THEY WERE EARNED NOT COMPENSATED, HOWEVER 2003 BONUSES EARNED HAVE NOT BEEN APPROVED BY THE COURT AND WON'T BE UNTIL 5/17/2004 SO ARE NOT DISCLOSED AT THIS TIME

**REPORTING IN PRIOR YEARS WAS BASED ON W-2. NOTE THIS YEAR(2003) WE ARE REPORTING DIFFERENTLY.

**Bonus/Incentives are reported in the year they are earned not paid.

**Benefits reflect the amounts the Employer Contributes to all Benefits noted in G > above

Note that the change in reporting makes the variance skewed from 2003 to 2002.

Note: This schedule contains the five most highly compensated corporate officers who are assigned or allocated to Montana.

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary (Wages)	Bonuses 1/		Other 2/		Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Gary Drook President and Chief Executive Officer	544,355	600,000	A	13,566 11,334 99,806 92,037	C E F H	1,361,098	N/A (employment began 1/3/03)	0%
2	Kipp Orme Vice President, Finance and Chief Financial Officer (resigned 2003)	184,215			21,154 12,438 263,000 4,400 1,873	B C D E I	487,080	326,949	49%
3	William Austin Chief Restructuring Officer	284,615			13,236 797 2,247	C G I	300,895	N/A (employment began 4/7/03)	0%
4	Michael Hanson Chief Operating Officer	355,609			14,856 5,035 8,025	C E J	383,525	1,057,605	-64%
5	Eric Jacobsen Vice President, General Counsel & Chief Legal Officer	314,968			15,833 4,778 3,745 6,905	C E I J	346,229	566,999	-39%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation

1/ Bonuses consist of the following:

A> Discretionary & NOR Bonus

1/ Bonuses shown were earned in the year shown and paid in the following year with the exception of a employment bonus to Gary Drook $600,000.

1/ Bonuses paid in 2003 but earned in 2002 are not listed above due to the change in how we are reporting include the following: Michael Hanson $440,000, Eric Jacobsen $250,000

2/ All Other Compensation for named employees consists of the following:

B> Vacation Sellbacks / Vacation Payout

C>Employer Contributions to Benefits-Medical, Dental, Vision, EAP/Carewise, Term Life, Group Term Life, 401k

D> Severance Payment

E> Vehicle Payment / Car Allowance

F> Payment for Relocation Expenses

G> Imputed Income

H> Fringe Airplane Gross-Up

I> Country Club Dues

J> Tax for Gross-up Pmts-SVIP Stk

**BONUSES ARE REPORTED IN THE YEAR THEY WERE EARNED NOT COMPENSATED, HOWEVER 2003 BONUSES EARNED HAVE NOT BEEN APPROVED BY THE COURT AND WON'T BE UNTIL 5/17/2004 SO ARE NOT DISCLOSED AT THIS TIME

**REPORTING IN PRIOR YEARS WAS BASED ON W-2. NOTE THIS YEAR(2003) WE ARE REPORTING DIFFERENTLY.

**Bonus/Incentives are reported in the year they are earned not paid.

**Benefits reflect the amounts the Employer Contributes to all Benefits noted in C > above

Note that the change in reporting makes the variance skewed from 2003 to 2002.

Sch. 18	BALANCE SHEET 1/			
	Account Title	This Year	Last Year	% Change
1	**Assets and Other Debits**			
2	**Utility Plant**			
3	101 Plant in Service	$1,622,304,365	$1,587,393,652	2.20%
4	105 Plant Held for Future Use	4,901	8,984	-45.45%
5	107 Construction Work in Progress	12,888,897	13,265,884	-2.84%
6	108 Accumulated Depreciation Reserve	(746,535,248)	(713,142,815)	4.68%
7	111 Accumulated Amortization & Depletion Reserves	(12,976,399)	(9,116,109)	42.35%
8	114 Electric Plant Acquisition Adjustments	399,030,704	399,030,704	0.00%
9	115 Accumulated Amortization-Electric Plant Acq. Adj.	(2,536,800)	(2,441,885)	3.89%
10	117 Gas Stored Underground-Noncurrent	32,599,489	33,414,607	-2.44%
11	**Total Utility Plant**	1,304,779,909	1,308,413,021	-0.28%
12	**Other Property and Investments**			
13	121 Nonutility Property	3,475,012	3,646,390	-4.70%
14	122 Accumulated Depr. & Amort.-Nonutililty Property	(54,552)	(24,641)	121.39%
15	123.1 Investments in Subsidiary Companies	(190,751)	12,402,929	-101.54%
16	123 Investments in Colstrip Unit 4 & YNP	38,492,491	42,480,052	-9.39%
17	124 Other Investments	4,529,363	22,974,086	-80.28%
18	128 Miscellaneous Special Funds	2,322,955	1,497,098	55.16%
19	**Total Other Property & Investments**	48,574,517	82,975,914	-41.46%
20	**Current and Accrued Assets**			
21	131 Cash	18,450,362	27,914,771	-33.90%
22	135 Working Funds	36,705	47,780	-23.18%
23	136 Temporary Cash Investments	-	-	-
24	141 Notes Receivable	39,321	-	-
25	142 Customer Accounts Receivable	42,001,390	30,506,362	37.68%
26	143 Other Accounts Receivable	7,082,397	7,597,704	-6.78%
27	144 Accumulated Provision for Uncollectible Accounts	(1,570,429)	(1,283,900)	22.32%
28	145 Notes Receivable-Associated Companies	-	-	-
29	146 Accounts Receivable-Associated Companies	452,285,517	71,434,340	>300.00%
30	151 Fuel Stock	-	-	-
31	154 Plant Materials and Operating Supplies	7,597,097	7,928,691	-4.18%
32	164 Gas Stored - Current	7,120,719	6,954,010	
33	165 Prepayments	34,974,471	8,032,735	>300.00%
34	171 Interest and Dividends Receivable	-	-	-
36	172 Rents Receivable	325,610	214,063	52.11%
37	173 Accrued Utility Revenues	40,394,293	30,537,915	32.28%
38	174 Miscellaneous Current & Accrued Assets	708,316	217,395	225.82%
39	**Total Current & Accrued Assets**	609,445,769	190,101,866	220.50%
40	**Deferred Debits**			
41	181 Unamortized Debt Expense	19,971,998	3,467,877	>300.00%
42	182 Regulatory Assets	161,631,465	160,907,518	0.45%
43	183 Preliminary Survey and Investigation Charges	-	-	-
44	184 Clearing Accounts	(78)	(78)	0.00%
45	185 Temporary Facilities	78	78	0.00%
46	186 Miscellaneous Deferred Debits	4,222,870	3,503,600	20.53%
47	189 Unamortized Loss on Reacquired Debt	2,993,902	3,300,790	-9.30%
48	190 Accumulated Deferred Income Taxes	106,190,840	112,240,970	-5.39%
49	191 Unrecovered Purchased Gas Costs	8,659,475	2,459,019	252.15%
50	**Total Deferred Debits**	303,670,550	285,879,774	6.22%
51	**TOTAL ASSETS and OTHER DEBITS**	$ 2,266,470,745	1,867,370,574	21.36%

Sch. 18	cont. **BALANCE SHEET 1/**			
	Account Title	This Year	Last Year	% Change
1	**Liabilities and Other Credits**			
2	**Proprietary Capital**			
3	201 Common Stock Issued	$ -	$ -	-
4	204 Preferred Stock Issued	-	-	-
5	207 Premium on capital stock	-	-	-
6	211 Miscellaneous Paid-In Capital	578,633,741	578,633,741	0.00%
7	213 Discount on Capital Stock	-	-	-
8	214 Capital Stock Expense	-	-	-
9	215 Appropriated Retained Earnings	-	-	-
10	216 Unappropriated Retained Earnings	98,422,947	63,824,632	54.21%
11	217 Reacquired capital stock	-	-	-
12	**Total Proprietary Capital**	677,056,688	642,458,373	5.39%
13	**Long Term Debt**			
14	221 Bonds	327,402,000	327,402,000	0.00%
15	224 Other Long Term Debt	395,200,000	133,000,000	197.14%
16	226 Unamortized Discount on Long Term Debt-Debit	(2,606,300)	(2,886,070)	-9.69%
17	**Total Long Term Debt**	719,995,700	457,515,930	57.37%
18	**Other Noncurrent Liabilities**			
19	227 Obligations Under Capital Leases-Noncurrent	3,081,181	6,022,866	-48.84%
20	228.1 Accumulated Provision for Property Insurance	482,612	(117,388)	>-300.00%
21	228.2 Accumulated Provision for Injuries and Damages	12,188,458	13,465,656	-9.48%
22	228.3 Accumulated Provision for Pensions and Benefits	39,554,182	52,521,282	-24.69%
23	228.4 Accumulated Miscellaneous Operating Provisions	149,529,369	163,671,391	-8.64%
24	**Total Other Noncurrent Liabilities**	204,835,801	235,563,807	-13.04%
25	**Current and Accrued Liabilities**			
25	231 Notes Payable	-	-	-
26	232 Accounts Payable	48,023,604	32,698,245	46.87%
27	233 Notes Payable to Associated Companies	-	-	-
28	234 Accounts Payable to Associated Companies	251,251,424	121,387,163	106.98%
29	235 Customer Deposits	3,821,680	2,472,985	54.54%
30	236 Taxes Accrued	23,693,007	27,662,203	-14.35%
31	237 Interest Accrued	8,347,304	4,438,793	88.05%
32	238 Dividends Declared	-	-	-
33	241 Tax Collections Payable	(68,273)	(118,384)	-42.33%
34	242 Miscellaneous Current and Accrued Liabilities	7,447,256	17,374,652	-57.14%
35	243 Obligations Under Capital Leases-Current	4,072,181	3,533,688	15.24%
36	**Total Current and Accrued Liabilities**	346,588,183	209,449,345	65.48%
37	**Deferred Credits**			
38	252 Customer Advances for Construction	22,840,988	21,993,098	3.86%
39	253 Other Deferred Credits	107,645,512	117,443,222	-8.34%
40	254 Regulatory Liabilities	17,308,100	48,833,050	-64.56%
41	255 Accumulated Deferred Investment Tax Credits	(1)	(1)	0.00%
42	257 Unamortized Gain on Reacquired Debt	-	3,867	-100.00%
43	281-283 Accumulated Deferred Income Taxes	170,199,773	134,109,883	26.91%
44	**Total Deferred Credits**	317,994,372	322,383,119	-1.36%
45	**TOTAL LIABILITIES and OTHER CREDITS**	$ 2,266,470,745	1,867,370,574	21.37%
46	1/ Includes CMP and Montana Power Capital I; excludes Colstrip Unit 4 and Yellowstone National Park.			
47				
48		(0)	(0)	
49	The financial results reported include income taxes that are based upon NorthWestern's tax basis for plant assets purchased from			
50	the Montana Power Company. This tax basis differs from amounts included in the most recently decided rate proceeding and			
51	results in a lower deferred tax credit. This change was made in order to prevent any possible violation of the normalization			
52	requirements of the federal income tax code. The change results in an increase in the reported rate base.			
53				

NOTES TO FINANCIAL STATEMENTS

(1) Management's Statement

The financial statements for the periods included herein have been prepared by NorthWestern Corporation (the "Corporation", "Debtor" or "we"), a debtor-in-possession, pursuant to the rules and regulations Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. These financial statements represent the Montana operations of NorthWestern Energy.

On September 14, 2003 (the "Petition Date"), we filed a voluntary petition for relief under the provisions of Chapter 11 of the Federal Bankruptcy Code (the Bankruptcy Code) in the United States Bankruptcy Court for the District of Delaware (Bankruptcy Court). Pursuant to Chapter 11 (as discussed further in Note 3), we retain control of our assets and are authorized to operate our business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. We have investments in subsidiaries that are not party to the Chapter 11 case and are not debtors.

(2) Nature of Operations and Basis of Consolidation

We are one of the largest providers of electricity and natural gas in the Upper Midwest and Northwest, serving approximately 608,000 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 through our energy division, NorthWestern Energy. On February 15, 2002, we completed the acquisition of the electric and natural gas transmission and distribution business of The Montana Power Company, or Montana Power. As a result of the acquisition, from February 15, 2002 through November 15, 2002, we distributed electricity and natural gas in Montana through our wholly owned subsidiary, NorthWestern Energy, LLC. Effective November 15, 2002, we transferred the electric and natural gas transmission and distribution operations of NorthWestern Energy, LLC to NorthWestern Corporation, and since that date, we have operated its business as part of our NorthWestern Energy division. We are operating our utility business under the common name "NorthWestern Energy" in all our service territories. The former NorthWestern Energy, LLC has been renamed "Clark Fork and Blackfoot, LLC."

(3) Chapter 11 Filing

As a result of our Chapter 11 filing, we operate our business as a "debtor-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code, the Federal Rules of Bankruptcy Procedure and applicable court orders. All vendors are being paid for all goods furnished and services provided after the Petition Date while under the supervision of the bankruptcy court. As a debtor-in-possession, we are authorized to continue to operate as an ongoing business, but may not engage in transactions outside the ordinary course of business without the approval of the Court, after notice and an opportunity for a hearing.

On September 16, 2003, following first day hearings held on September 15, 2003, the Bankruptcy Court entered orders granting us authority to, among other things, pay prepetition and postpetition employee wages, salaries, benefits and other employee obligations, pay selected vendors and other providers for the postpetition delivery of goods and services, continue bank accounts and existing cash management system, and continue existing forward power contracts and enter into additional similar contracts in the ordinary course of business. On November 7, 2003, the Bankruptcy Court entered a final order to approve access of up to $85 million of the $100 million debtor-in-possession financing facility arranged by the company with Bank One, N.A. In December 2003, we reduced the commitment to $85 million and in April 2004, we further reduced the commitment to $75 million under this facility. The DIP Facility expires on September 12, 2004, and bears interest at a variable rate tied to the Eurodollar rate plus a spread of 3.00% or at the prime rate plus a spread of 1.00%. The DIP Facility will provide a source of liquidity during the course of our bankruptcy, but requires that we maintain certain other financial covenants and restricts liens, indebtedness, capital expenditures, dividend payments and sales of assets. As of December 31, 2003, there were $15.2 million in letters of credit outstanding and no borrowings under the DIP Facility.

In January 2004, the Bankruptcy Court extended our exclusive period to file a plan of reorganization through and including March 12, 2004, and extended the time to solicit votes on our plan of reorganization through and including May 11, 2004. We filed our initial plan of reorganization on March 12, 2004.

The financial statements have been prepared on a "going concern" basis in accordance with GAAP. The "going concern" basis of presentation assumes that we will continue in operation for the foreseeable future and will be able to realize our assets and discharge our liabilities in the normal course of business. Because of the Chapter 11 case and the circumstances leading to the filing thereof, our ability to continue as a "going concern" is subject to substantial doubt and is dependent upon, among other things, confirmation of a plan of reorganization, our ability to comply with the terms of the DIP Facility, and our ability to generate sufficient cash flows from operations, asset sales and financing arrangements to meet our obligations. There can be no assurance that this can be accomplished and if it were not, our ability to realize the carrying value of our assets and discharge our liabilities would be subject to substantial uncertainty. Therefore, if the "going concern" basis were not used for the Financial Statements, then significant adjustments could be necessary to the carrying value of assets and liabilities, the revenues and expenses reported, and the balance sheet classifications used.

The Chapter 11 filing triggered defaults, or termination events, on substantially all of our debt and lease obligations, and certain contractual obligations. Subject to certain exceptions under the Bankruptcy Code, our Chapter 11 filing automatically enjoined, or stayed, the continuation of any judicial or administrative proceedings or other actions against us or our property to recover on, collect or secure a claim arising prior to the Petition Date. Thus, for example, creditor actions to obtain possession of our property, or to create, perfect or enforce any lien against our property, or to collect on or otherwise exercise rights or remedies with respect to a prepetition claim are enjoined unless and until the Bankruptcy Court lifts the automatic stay.

(4) Significant Accounting Policies

Basis of Accounting

Our accounting policies conform with generally accepted accounting principles. With respect to our utility operations, these policies are in accordance with the accounting requirements and ratemaking practices of applicable regulatory authorities.

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. This report differs from generally accepted accounting principles due to FERC requiring the reflection of subsidiaries on the equity method of accounting which differs from Statement of Financial Accounting Standards No. 94 "Consolidation of All Majority-Owned Subsidiaries" (SFAS No. 94). SFAS No. 94 requires that all majority-owned subsidiaries be consolidated. The other significant differences are comparative statements of retained earnings and cash flows and net income per share are not presented.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires us 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 long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, uncollectible accounts, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

For our Montana operations, as prescribed by the MPSC, operating revenues are recorded monthly on the basis of consumption or services rendered. Customers are billed monthly on a cycle basis.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable

Accounts receivable includes accrued unbilled revenues of $40.7 million and $30.6 million at December 31, 2003 and 2002.

Inventories

Inventories are stated at the lower of cost or market, with cost determined using the average cost method.

Regulatory Assets and Liabilities

Our regulated operations are subject to the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulations* (SFAS No. 71). Regulatory assets represent probable future revenue associated with certain costs, which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process.

If all or a separable portion of our operations becomes no longer subject to the provisions of SFAS No. 71, an evaluation of future recovery of the related regulatory assets and liabilities would be necessary. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Investments

Investments consisted of life insurance contracts and other investments in the amount of $4.5 million and $23 million at December 31, 2003 and 2002, respectively.

Life insurance contracts are carried at their cash surrender value. We also have investments in various money market accounts and other items. Investments in life insurance contracts of $3.6 million and $22.2 million are held in trust and restricted for postretirement benefits as of December 31, 2003 and 2002, respectively. Investments in money market accounts of $3.6 million and $3.8 million are restricted to satisfy certain debt requirements as of December 31, 2003 and 2002, respectively.

Derivative Financial Instruments

We manage risk using derivative financial instruments for changes in electric and natural gas supply prices and interest rate fluctuations.

We periodically use commodity futures contracts to reduce the risk of future price fluctuations for electric and natural gas contracts. Increases or decreases in contract values are reported as gains and losses in our Statements of Income (Loss) unless the commodities are specifically subject to supply tracking mechanisms within the regulatory environment.

The fair value of fixed-price commodity contracts is estimated based on market prices of commodities covered by the contracts. As of December 31, 2003, we have outstanding call obligations for physical delivery of 3.3 million MMBTU of natural gas during February and March of 2004. We have recorded a liability related to these obligations of $1.8 million based on the market value of natural gas as of December 31, 2003. We settled these calls during January and February 2004, resulting in a gain of approximately $526,000.

Property, Plant and Equipment

Property, plant and equipment are stated at cost. Depreciation is computed using the straight-line method based on the estimated useful lives of the various classes of property, ranging from 3 to 40 years.

All expenditures for maintenance and repairs of utility property, plant and equipment are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal.

Property, plant and equipment at December 31 consisted of the following (in thousands):

	2003	2002
Land and improvements	$ 33,255	$ 29,344
Building and improvements	59,928	62,870
Storage, distribution, transmission and generation	1,415,459	1,374,965
Construction work in process	12,889	13,266
Electric plant acquisition adjustments	399,031	399,031
Other equipment	146,266	153,638
	2,066,828	2,033,114
Less accumulated depreciation	(762,048)	(724,701)
	$ 1,304,780	$ 1,308,413

We capitalize the cost of plant additions and replacements, including an allowance for funds used during construction (AFUDC) of utility plant. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.9% and 8.7% for Montana for 2003 and 2002, respectively. Interest capitalized totaled $0.9 million and $1.0 million in 2003 and 2002, respectively, for Montana.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from three to forty years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.5%, 3.4% and 3.3% for 2003, 2002 and 2001, respectively.

Income Taxes

Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas costs, which are deferred for book purposes but expensed currently for tax purposes, and net operating loss carry forwards.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset based on our expectation that we will recover these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution control equipment, we capitalize and depreciate the costs over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

We record estimated remediation costs, excluding inflationary increases and probable reductions for insurance coverage and rate recovery. The estimates are based on our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

New Accounting Standards

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, *Accounting for Asset Retirement Obligations,* which was effective January 1, 2003. The statement provides accounting and disclosure requirements for retirement obligations associated with long-lived assets. The statement requires the present value of future asset retirement costs for which the Corporation has a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the asset life.

We have completed an assessment of the specific applicability and implications of SFAS No. 143. We have identified, but have not recognized, asset retirement obligation, or ARO, liabilities related to our electric and natural gas transmission and distribution assets. Many of these assets are installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

Our regulated utility operations recognize removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. These amounts do not represent SFAS No. 143 legal retirement obligations. As of December 31, 2003 and 2002, we have estimated accrued removal costs of $124.9 million and $115.5 million, respectively.

SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*, was issued in April 2002. SFAS No. 145 eliminates the requirement that gains and losses from the extinguishments of debt be aggregated and classified as extraordinary items, net of the related income tax. It also requires sale-leaseback treatment for certain modifications of a capital lease that result in the lease being classified as an operating lease. We adopted SFAS No. 145 on January 1, 2003 and our loss on debt extinguishment is reflected as miscellaneous non-operating on the Statement of Income (Loss). The related tax benefit of $7.2 million is reflected as a benefit for income taxes on the Statement of Income (Loss).

SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, was issued in June 2002. SFAS No. 146 requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan, including lease termination costs and certain employee termination benefits that are associated with a restructuring, discontinued operation, plant closing or other exit or disposal activity. SFAS No. 146 is being applied prospectively and is effective for exit or disposal activities that are initiated after December 31, 2002. We adopted SFAS No. 146 on January 1, 2003. The adoption of SFAS No. 146 did not have a material impact on our results of operations, financial position, or cash flows.

FASB Interpretation No. 46, *Consolidation of Variable Interest Entities* (FIN 46), was issued in January 2003 and was revised in December 2003. This interpretation changes the method of determining whether certain entities, including securitization entities, should be included in a company's financial statements. An entity that is subject to FIN 46 is called a variable interest entity, or VIE, if it has equity that is insufficient to permit the entity to finance its activities without additional subordinated financial support from other parties, or equity investors that cannot make significant decisions about the entity's operations, or that do not absorb the expected losses or receive the expected returns of the entity. All other entities are evaluated for consolidation in accordance with SFAS No. 94, *Consolidation of All Majority-Owned Subsidiaries*. A VIE is by its primary beneficiary, which is the party involved with the VIE that has a majority of the expected losses or a majority of the expected residual returns or both. The requirements of FIN 46 are applicable to NorthWestern Corporation in the fourth quarter of 2003. Had we not filed for bankruptcy, we would have been required to deconsolidate our Subsidiary Trusts, which hold our Company Obligated Mandatorily Redeemable Preferred Securities (TPS), upon adoption of FIN 46. However, upon filing for bankruptcy, the Subsidiary Trusts were terminated and the TPS became direct obligations of NorthWestern Corporation. In February 2004, we became aware that certain long-term purchase power and tolling contracts may be considered variable interests under FIN No. 46R. We have various long-term purchase power contracts with other utilities and certain qualifying facility plants. We believe the counterparties to these contracts are not special-purpose entities and, therefore, FIN No. 46R would not apply to these contracts until March 31, 2004. We have not yet completed our evaluation of these contracts to determine if we need to consolidate these counterparties under FIN No. 46R and will continue to monitor developing practice in this area.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, which amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS No. 149 is effective prospectively for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The exception to these requirements are the provisions of SFAS No. 149 related to SFAS No. 133 implementation issues that have been effective for fiscal quarters that began prior to June 15, 2003, should continue to be applied in accordance with their respective effective dates. In addition, paragraphs 7(a) and 23(a), which relate to forward purchases or sales of when-issued securities or other securities that do not yet exist, should be applied to both existing contracts and new contracts entered into after June 30, 2003. The adoption of SFAS No. 149 did not have a material impact on our results of operations, financial condition or cash flows.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity*, which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 requires that an issuer classify a financial instrument that is within its scope, which may have previously been reported as equity, as a liability or an asset in some circumstances. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. In accordance with SFAS No. 150, we have presented our Company Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts as liabilities and the respective dividends have been reflected as interest expense.

Reclassifications

Certain 2002 amounts have been reclassified to conform to the 2003 presentation. Such reclassifications had no impact on net income (loss) or shareholders' equity (deficit) as previously reported.

(5) Acquisitions

On February 15, 2002, we completed the asset acquisition of Montana Power's energy transmission and distribution business for $478.0 million in cash and the assumption of $511.1 million in existing debt and mandatorily redeemable preferred securities of subsidiary trusts (net of cash received). Acquisition costs were approximately $24.8 million. We completed this acquisition to expand our presence in the energy market. As a result of the acquisition, we are now a provider of natural gas and electricity to approximately 608,000 customers in Montana, South Dakota and Nebraska. Results of our Montana operations have been included in the accompanying financial statements since the effective date of the acquisition.

(6) Goodwill

We adopted the provisions of SFAS No. 142 effective January 1, 2002, and goodwill is no longer amortized. According to the guidance set forth in SFAS No. 142, we are required to evaluate our goodwill and indefinite-lived intangible assets for impairment at least annually (October 1) and more frequently when indications of impairment exist. Accounting standards require that if the fair value of a reporting unit is less than its carrying value including goodwill, an impairment charge for goodwill must be recognized in the financial statements. To measure the amount of the impairment loss to recognize, we compare the implied fair value of the reporting unit's goodwill with its carrying value. This methodology differs from our previous policy, as permitted under previous accounting standards, of using undiscounted cash flows on an enterprise wide basis to determine if goodwill is recoverable.

We determined that our Chapter 11 bankruptcy filing constitutes an event that may reduce the fair value of our reporting unit below its carrying value. Therefore we retained a third party to assist us in completing a goodwill impairment test as required by SFAS No. 142. Fair value was determined using a discounted cash flow approach and a guideline company market approach. Completion of the testing indicated that no impairment charge was required.

There were no changes in our goodwill during the 12 months ended December 31, 2003. Goodwill relates entirely to the Montana operations acquired in 2002 and is reflected in the Balance Sheets as a plant acquisition adjustment of $375.8 million as of December 31, 2003 and 2002.

(7) (This Footnote was Intentionally Left Blank)

(8) (This Footnote was Intentionally Left Blank)

(9) Long-Term Debt

Long-term debt at December 31 consisted of the following (in thousands):

	Due	2003	2002
Senior Secured Term Loan	2006	277,200	—
Mortgage bonds—			
Montana—7.30%	2006	150,000	150,000
Montana—8.25%	2007	365	365
Montana—8.95%	2022	1,446	1,446
Montana—7.00%	2005	5,386	5,386
Pollution control obligations—			
Montana—6.125%	2023	90,205	90,205
Montana—5.90%	2023	80,000	80,000
Secured medium term notes—			

7.23%	2003	—	15,000
7.25%	2008	13,000	13,000
Unsecured medium term notes—			
7.07%	2006	15,000	15,000
7.875%	2026	20,000	20,000
7.96%	2026	5,000	5,000
Quips — 8.45%		65,000	65,000
Discount on Notes and Bonds	—	(2,606)	(2,886)
		$ 719,996	$ 457,516

On September 14, 2003, the Bankruptcy Court gave interim approval for access of up to $50 million of our $100 million DIP Facility. On November 7, 2003, the Bankruptcy Court entered a final order to approve the DIP Facility and, in doing so, increased our access under this facility to $85 million. In December 2003, we reduced the commitment to $85 million and in April 2004, we further reduced the commitment to $75 million under this facility. The DIP Facility expires on September 12, 2004, and bears interest at a variable rate tied to the Eurodollar rate plus a spread of 3.00% or at the prime rate plus a spread of 1.00%. The DIP Facility requires that we maintain certain other financial covenants and restricts liens, indebtedness, capital expenditures, dividend payments and sales of assets. As of December 31, 2003, we had $15.2 million in letters of credit outstanding and no borrowings under the DIP facility.

We have reached an agreement with the lenders holding claims under our senior credit facility agented by CSFB to amend the terms of our $390 million prepetition credit facility. In January 2004, the Bankruptcy Court entered a final order authorizing the amendment of the credit facility and granting protection in connection therewith. The amended credit facility provides advantages to NorthWestern, including lower interest expense allowing reinstatement upon NorthWestern's emergence from Chapter 11. At NorthWestern's option, the amended credit facility bears interest at a variable rate tied to the Eurodollar rate, plus a spread of 5.50%, or at an alternate base rate, as defined by the amended credit facility, plus a spread of 3.50%. There is no longer a minimum floor for the Eurodollar rate or the alternate base rate. As a result of this amendment, we estimate annualized interest expense will be reduced by approximately $6 million to $8 million.

Our senior secured term loan expires on December 1, 2006, and requires quarterly amortization payments equal to $975,000. The credit agreement contains financial covenants related to minimum EBITDAR(1), maximum capital expenditures and a number of other representations and warranties. We are in compliance with these debt covenants at December 31, 2003.

In January 2003, in connection with executing the new senior secured term loan facility, we applied to the MPSC for authorization to issue up to $280 million aggregate principal amount of First Mortgage Bonds secured by Montana utility assets as security for our new senior secured term loan facility. In granting its approval, the MPSC placed the following conditions on the approval of the First Mortgage Bonds:

- We must apply all proceeds from the sale of nonutility assets, specifically including Blue Dot and Expanets, to debt reduction;
- We must commit to fully funding the operation, maintenance, repair and replacement of our public utility infrastructure in Montana, and we were required to file a maintenance plan and budget with the MPSC by March 13, 2003;
- We may not provide more than an additional $10 million in aggregate in capital to any nonutility entity without the prior approval of the MPSC;
- We must report all advances to nonutility companies to the MPSC within 5 business days of such advance; and
- if the existing credit agreements for Blue Dot or Expanets are terminated, we may file an application with the MPSC seeking approval to provide secured loans of up to $20 million to Blue Dot and up to $30 million to Expanets.

The South Dakota Mortgage Bonds are two series of general obligation bonds we issued under our South Dakota indenture, and the South Dakota Pollution Control Obligations are three obligations under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds are four series of bonds that The Montana Power Company issued. The Montana Pollution Control Obligations, and the Secured Medium Term Notes are obligations that The Montana Power Company issued. The Montana Natural Gas Transition Bonds were issued by The Montana Power Company. All of these obligations are secured by substantially all of our Montana electric and natural gas assets.

The Senior Notes are two series of unsecured notes that we issued in 2002 in connection with our acquisition of NorthWestern Energy LLC. Proceeds were used for the acquisition and for general corporate purposes.

The Senior Unsecured Debt is a general obligation that we issued in November 1998. The proceeds were used to repay short-term indebtedness and for general corporate purposes.

The Unsecured Medium Term Notes are general obligations issued by The Montana Power Company.

The aggregate minimum principal maturities of long-term debt, absent accelerations due to default, during the next five years are $2.8 million in 2004, $8.2 million in 2005, $436.6 million in 2006, $0.4 million in 2007 and $13.0 million in 2008.

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(1) EBITDAR is earnings before interest, taxes, depreciation, amortization and non-recurring restructuring expenses. EBITDAR is a non-GAAP financial measure and as such, we have not used it in describing our results of operations. We have used EBITDAR in this section specifically to show compliance with our debt covenants, and we do not refer to EBITDAR for any other purpose herein.

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(10) Comprehensive Income (Loss)

Comprehensive income is the sum of net income as reported and other comprehensive income. Our other comprehensive income primarily resulted from our foreign currency translation adjustment.

The after tax components of accumulated other comprehensive income for the years ended December 31, 2003 and 2002, were as follows (in thousands):

	2003	2002
Balance at December 31,		
Other Comprehensive Income:		
Foreign currency translation adjustment	158	122
Accumulated other comprehensive loss	$ 158	$ 122

The accumulated balance of other comprehensive income at December 31, 2003 and 2002 was $2.4 million and $2.2 million, respectively.

(11) Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, *Disclosures About Fair Value of Financial Instruments*. The estimated fair-value amounts have been determined using available market information and appropriate valuation methodologies. However, considerable judgment is necessarily required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

- The carrying amounts of cash and cash equivalents, restricted cash and investments approximate fair value due to the short maturity of the instruments. The fair value of life insurance contracts is based on cash surrender value.
- Fair values for debt were determined based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, which is based on market prices.
- The fair value of preferred securities of subsidiary trusts is based on current market prices.
- The fair-value estimates presented herein are based on pertinent information available to us as of December 31, 2003. Although we are not aware of any factors that would significantly affect the estimated fair-value amounts, such amounts have not been comprehensively revalued for purposes of these financial statements since that date, and current estimates of fair value may differ significantly from the amounts presented herein.

The estimated fair value of financial instruments at December 31 is summarized as follows (in thousands):

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				

Cash and cash equivalents	$ 18,487	$ 18,487	$ 27,963	$ 27,963
Investments	4,529	4,529	22,974	22,974
Liabilities:				
Long-term debt (including current portion)	719,996	695,516	457,516	426,553

(12) Income Taxes

Income tax benefit applicable to continuing operations before minority interests for the years ended December 31 is comprised of the following (in thousands):

	2003	2002
Federal		
Current	$ (9,906)	$ 5,900
Deferred	37,717	4,594
Investment tax credits		
State	317	2,586
	$ 28,128	$ 13,080

The following table reconciles our effective income tax rate to the federal statutory rate:

	2003	2002
Federal statutory rate	35.00%	35.00%
State income, net of federal provisions	4.24%	5.02%
Amortization of investment tax credit	0.00%	0.00%
Reversal of Utility book/tax depreciation	5.33%	-11.10%
Other, net	0.48%	-3.52%
	45.06%	25.39%

The components of the net deferred income tax liability recognized in our Consolidated Balance Sheets are related to the following temporary differences at December 31 (in thousands):

	2003	2002
Amortization of gain on sale/leaseback	$ 2,957	$ 3,379
Other	103,234	108,862
	106,191	112,241
Plant Related	(147,139)	(94,173)
Other, net	(23,061)	(39,937)
	(170,200)	(134,110)
	$ (64,009)	$ (21,869)

(13) (This Footnote was Intentionally Left Blank)

(14) (This Footnote was Intentionally Left Blank)

(15) Employee Benefit Plan

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for employees of the corporation and regulated utility division. In addition, we also sponsor nonqualified, unfunded defined benefit pension plans for certain officers and other employees. With the acquisition of Montana Power, we assumed their pension and postretirement health care plans. These plans are reflected in the 2003 and 2002 columns of the tables below.

Net periodic cost for our pension and other postretirement plans consists of the following for the year ended December 31 (in thousands):

	Pension Benefits			Other Postretirement Benefits	
Components of Net Periodic Benefit Cost	2003	2002	2001	2003	2002

(Income)					
Service cost	$ 4,326	$ 4,144	$ 4,731	$ 814	$ 550
Interest cost	17,729	17,345	18,028	3,573	3,555
Expected return on plan assets	(13,419)	(16,475)	(20,547)	(261)	(399)
Amortization of transitional obligation.	—	(41)	(20)		789
Amortization of prior service cost	—	1,960	2,094	—	28
Recognized actuarial (gain) loss	1,934	—	—	692	633
	10,570	6,933	4,286	4,818	5,156
Additional (income) or loss recognized:					
Curtailment	—	910	(2,315)	—	804
Special termination benefits	—	4,191	—	—	168
Settlement cost	—	3,744	(770)	(1,798)	—
Net Periodic Benefit Cost	$ 10,570	$ 15,778	$ 1,201	$ 3,020	$ 978

The prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of 10% of the greater of the benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

Following is a reconciliation of the changes in plan benefit obligations and fair value and a statement of the funded status as of December 31 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
Reconciliation of Benefit Obligation				
Obligation at January 1	$ 275,899	$ 259,971	$ 58,291	$ 46,537
Service cost	4,326	4,144	814	550
Interest cost	17,729	17,345	3,573	3,555
Actuarial loss	19,855	16,537	8,040	17,422
Plan amendments	—	—	)	(983)
Acquisitions/Divestitures		(11,835)		(1,201)
Curtailments	—	—	)	—
Settlement cost	—	—	(16,566)	—
Special termination benefits		4,191	—	168
Gross benefits paid	(16,957)	(14,454)	(4,354)	(7,757)
Benefit obligation at end of year	$ 300,852	$ 275,899	$ 49,798	$ 58,291
Reconciliation of Fair Value of Plan Assets				
Fair value of plan assets at January 1	$ 163,468	$ 215,144	$ 4,869	$ 5,872
Actual return on plan assets	32,482	(21,290)	309	(767)
Acquisitions/Divestitures	—	(15,932)	—	—
Employer contributions	9,700	—	21,176	7,521
Settlements	—	—	(16,566)	—
Gross benefits paid	(16,957)	(14,454)	(4,354)	(7,757)
Fair value of plan assets at end of year	$ 188,693	$ 163,468	$ 5,434	$ 4,869

The total projected benefit obligation and fair value of plan assets for the pension plans with projected benefit obligations in excess of plan assets were $300.9 million and $188.7 million, respectively, as of December 31, 2003. The total accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $292.3 million and $188.7 million, respectively, as of December 31, 2003. The total projected benefit obligation and fair value of plan assets for the pension plans with projected benefit obligations in excess of plan assets were $275.9 million and $163.9 million, respectively, as of December 31, 2002. The total accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $268.3 million and $163.9 million, respectively, as of December 31, 2002.

In January 2004, the Financial Accounting Standards Board issued FASB Staff Position No. FAS 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (FSP 106-1). While we have elected to defer recognition of the effects of FSP 106-1 until guidance on the accounting for the federal subsidy is issued, we do not expect the effects of FSP 106-1 to be material to the measurement of our APBO or our net periodic postretirement benefit cost.

The accrued pension and other postretirement benefit obligations recognized in the accompanying Balance Sheets are computed as follows for the years ended December 31 (in thousands):

	Pension Benefits 2003	Pension Benefits 2002	Other Postretirement Benefits 2003	Other Postretirement Benefits 2002
Funded Status	$ (112,159)	$ (112,431)	$ (44,364)	$ (53,422)
Unrecognized transition amount	—	(82)	—	7,932
Unrecognized net actuarial loss	48,824	77,976	15,622	17,822
Unrecognized prior service cost	—	18,499	—	237
Accrued benefit cost	$ (63,335)	$ (16,038)	$ (28,742)	$ (27,431)
Prepaid benefit cost	$ —	$ —	$ —	$ —
Accrued benefit cost	(63,335)	(16,038)	(28,742)	(27,431)
Additional minimum liability	(40,233)	88,813	—	—
Intangible asset	—	(18,499)	—	—
Regulatory asset	—	—	—	—
Accumulated other comprehensive income	40,233	(70,314)	—	—
Net amount recognized	$ (63,335)	$ (16,038)	$ (28,742)	$ (27,431)

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits 2003	Pension Benefits 2002	Pension Benefits 2001	Other Postretirement Benefits 2003	Other Postretirement Benefits 2002
Discount rate	6.00%	7.00%	7.00%	6.0-6.5%	6.0-6.5%
Expected rate of return on assets	8.50%	8.50%	9.00%	8.5%	8.5%
Long-term rate of increase in compensation levels (nonunion)	3.97%	3.97%	4.40%	—	—

The expected long-term rate of return assumption on plan assets for both the NorthWestern Energy and NorthWestern Corporation pension and postretirement plans was determined based on the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension and postretirement portfolios. Over the 15-year period ending December 31, 2002, the returns on these portfolios, assuming they were invested at the current target asset allocation in prior periods, would have been a compound annual average of approximately 10.1%. Considering this information and the potential for lower future returns due to a generally lower interest rate environment, we selected an 8.5% long-term rate of return on assets assumption.

Our investment goals with respect to managing the pension and other postretirement assets is to achieve and maintain a fully funded status for the pension plans, improve the status of the health and welfare plan, minimize contribution requirements, and seek long-term growth by placing primary emphasis on capital appreciation and secondary emphasis on income, while minimizing risk.

Pension funding is based upon annual actuarial studies prepared for each plan. For our postretirement welfare benefits, our policy is to contribute an amount equal to the annual actuarially determined cost that is also recoverable in rates. We generally fund our 401(h) and VEBA trusts monthly, subject to our liquidity needs and the maximum deductible amounts allowed for income tax purposes.

The company's investment policy for fixed income investments are oriented toward risk adverse, investment-grade securities rated "A" or higher and are required to be diversified among individual securities and sectors (with the exception of U.S. Government securities, in which the plan may invest the entire fixed income allocation) and there is no limit on the maximum maturity of securities held. In addition, the NorthWestern Corporation pension plan assets also includes a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities, reflected at current market values with a market adjustment.

Equity investments per the investment policy can include convertible securities, and are required to be diversified among industries and economic sectors. Limitations are placed on the overall allocation to any individual security at both cost and market value and international equities investments are diversified by country. In addition, there are limitations on investments in emerging markets.

Our investment policy prohibits short sales, margin purchases and similar speculative transactions as well as any transactions that would threaten tax exempt status of the fund, actions that would create a conflict of interest or transactions between fiduciaries and parties in interest as defined under ERISA. With respect to international investments, foreign currency hedging is allowed under the policy for the purpose of hedging currency risk and to effect securities transactions. Permissible investments include foreign currencies in both spot and forward markets, options, futures, and options on futures in foreign currencies.

The target asset allocation percentages are as follows, within an allowable range of plus or minus 5%:

	Pension Benefits	Other Benefits
Cash and cash equivalents	—	—
Debt securities	30.0%	30.0%
Domestic equity securities	60.0%	60.0%
International equity securities	10.0%	10.0%
Other	—	—

The percentage of fair value of plan assets held in the following investment types by the NorthWestern Energy pension plan, NorthWestern Corporation pension plan and NorthWestern Energy Health and Welfare Plan as of December 31, 2003 and 2002, are as follows:

	NorthWestern Energy Pension		NorthWestern Energy Health and Welfare	
	2003	2002	2003	2002
Cash and cash equivalents	1.4%	7.2%	2.8%	4.0%
Debt securities	28.5%	33.4%	27.5%	30.4%
Domestic equity securities	58.9%	54.2%	68.3%	64.7%
International equity securities	11.2%	5.2%	1.4%	0.9%
Participating group annuity contracts	—	—	—	—
	100.0%	100.0%	100.0%	100.0%

At December 31, 2002, the NorthWestern Energy pension plan investment portfolio was undergoing a change in investment managers, Domestic equity investments were liquidated and pending reinvestment by the new investment manager. This was completed and the portfolio was again rebalanced to bring it within the target asset allocation during 2003. We also began the process of transitioning NorthWestern Corporation's pension plan assets over to comply with the new investment policy asset target guidelines adopted in 2002. At December 31, 2003, this process was partially completed with the liquidation and diversified reinvestment of part of the plan assets. We are evaluating the potential for liquidating and reinvesting the assets held in participating group annuity contracts as rebalancing and diversification opportunities are currently limited with respect to this portion of plan assets.

We estimate contributions to our pension and other benefit plans in 2004 to be approximately $16.0 million in total.

The rate of increase in per capita costs of covered health care benefits is assumed to be 11% in 2004, decreasing gradually to 5% by the year 2009. The following table sets forth the sensitivity of retiree welfare results (in thousands):

Effect of a one percentage point increase in assumed health care cost trend		
on total service and interest cost components	$	239
on postretirement benefit obligation		2,488
Effect of a one percentage point decrease in assumed health care cost trend		
on total service and interest cost components	$	(191)
on postretirement benefit obligation		(1,943)

Pension costs in Montana are included in rates on a pay as you go basis for regulatory purposes. Other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. (See Note 17, Regulatory Assets and Liabilities, for the regulatory assets related to our pension and other postretirement benefit plans.)

During 2003 and 2002, we made available to select employees an early retirement program. The impact of that reduction in participants resulted in the special termination benefits presented in the above table.

We provide various employee savings plans, which permit employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the Plans, the employees may elect to direct a percentage of their gross compensation to be contributed to the Plans. We contribute up to a maximum of 4.0% of the employee's gross compensation contributed to the Plan. Costs incurred under these plans were $2.5 million and $2.7 million in 2003, and 2002, respectively.

(16) (This Footnote was Intentionally Left Blank)

(17) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 4 to the Financial Statements. Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are recognized when included in rates and recovered from or refunded to the customers. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. We have specific orders to cover approximately 98% of our regulatory assets and approximately 98% of our regulatory liabilities.

	Note Ref.	Remaining Amortization Period	2003	2002
Pension	15	Undetermined	$ 43,818	$ 42,696
SFAS No. 106 purchase obligation	15	Undetermined	4,020	4,174
Income taxes	12	Plant lives	63,841	62,908
Other		Various	11,009	11,950
Total regulatory assets			$ 122,688	$ 121,728
Gas storage sales		36 Years	$ 15,036	$ 15,456
Proceeds from oil and gas sale		—	—	15,982
Utility sale stipulation agreement		—	—	16,254
Other		Various	2,272	6,794
Total regulatory liabilities			$ 17,308	$ 54,486

A pension regulatory asset has been recognized upon the purchase of Montana Power for the obligation that will be included in future cost of service. Pension costs in Montana are recovered in rates on a cash basis. Competitive transition charges relate to natural gas properties and earn a rate of return sufficient to meet the debt service requirements of the Montana natural gas transition bonds. A regulatory asset has been recognized for the SFAS No. 106 purchase obligation upon the purchase of Montana Power. The MPSC allows recovery of SFAS No. 106 costs on an accrual basis. A regulatory asset has been recorded to reflect the future recovery of energy supply costs through the ratemaking process. Tax assets and liabilities primarily reflect the effects of plant related temporary differences such as removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates.

During 2001, Montana Power made sales of natural gas from its storage field at prices in excess of its original cost, creating a regulatory liability. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas and was fully amortized through rates in 2003. Montana Power also has a regulatory liability related to oil and gas proceeds that was credited to customer bills on a monthly basis. In connection with the acquisition of Montana Power, a stipulation agreement was signed that required a contribution by the previous owner and us to fund credits to Montana electric distribution customers. The account was applied on a kilowatt hour basis beginning July 1, 2002 for one year.

(18) Deregulation and Regulatory Matters

Deregulation

The electric and natural gas utility businesses in Montana are operating in a competitive market in which commodity energy products and related services are sold directly to wholesale and retail customers.

Electric

Montana's Electric Utility Industry Restructuring and Customer Choice Act (Electric Act), was passed in 1997. Various energy-related legislation revised and refined the Act during the legislative sessions that followed. The 2003 Legislature established us as the permanent default supplier and set the transition period for all customers to be able to choose their electric supplier to end July 1, 2027. As default supplier, we are obligated to continue to supply electric energy to customers in our service territory who have not chosen, or have not had an opportunity to choose, other power suppliers. The 2003 legislation also requires smaller customers to remain as default supply customers and established a specific set of requirements and procedures that guide power supply procurements and their cost recovery. This provides adequate assurances of recovering our costs of acquiring electric supply.

On January 23, 2003, we filed our first biannual Electric Default Supply Resource Procurement Plan with the PSC, which fulfills the requirements established by law and describes the planning we are doing on behalf of our electric default supply customers to acquire a balanced and well designed resource portfolio. We have a substantial portion of the portfolio covered by the existing PPL Montana base-load contracts and the QF contracts.

Natural Gas

Montana's Natural Gas Utility Restructuring and Customer Choice Act, also passed in 1997, provides that a natural gas utility may voluntarily offer its customers choice of natural gas suppliers and provide open access. We have opened access on our gas transmission and distribution systems, and all of our natural gas customers have the opportunity of gas supply choice. We are also the default supplier for the remaining natural gas customers.

Regulatory Matters

The MPSCregulates our bundled transmission and distribution, services and approves the rates that we charge for these services, while the FERC regulates our transmission services. Current regulatory issues are discussed below.

On August 12, 2003, the MCC filed a Petition for Investigation, Adoption of Additional Regulatory Controls and Related Relief with the MPSC. On August 22, 2003, the MPSC issued an order initiating an investigation of us relating to, among others, finances, corporate structure, capital structure, cash management practices, and affiliated transactions. The relief sought includes adoption of new regulatory controls that would specifically apply to us including additional reporting, cost allocation and financing rules and requirements, and examination of affiliate transactions necessary to ensure that we are not operating our energy division, and will not in the future operate, in a manner that would prejudice our ability to furnish reasonably adequate service and facilities at reasonable and just charges as required under Montana law. A procedural schedule was set in January 2004 with a hearing tentatively scheduled for June 2004. We cannot determine the impact or resolution of this petition, however, any action taken by the MPSC to increase the regulatory controls under which we operate may have a material affect on our liquidity, operations and financial condition. If we are unable to comply with any MPSC orders in a timely manner, we may become subject to material monetary penalties and fines. We are cooperating with the MCC in the discovery process, but have retained the right to argue that the investigation is stayed as a result of our Chapter 11 filing.

Electric Rates

On June 12, 2003, the MPSC approved the next annual tracking period for the stipulated competitive transition charges Qualifying Facilities Contracts, or CTC-QFs in the amount of $17.4 million to be effective July 1, 2003. On June 16, 2003, we filed our annual electric supply cost tracker request with the MPSC for any unrecovered actual electric supply costs for the 12-month period ended June 30, 2003, and for projected costs for the 12-month period ended June 30, 2004. On July 15, an interim order was approved by MPSC for the projected electric supply cost.

Natural Gas Rates

On June 2, 2003, we filed an annual gas cost tracker request with the MPSC for any unrecovered actual gas costs for the eight-month period ended June 30, 2003, and for the projected gas costs for the 12-month period ending June 30, 2004. On July 3, 2003, the MPSC issued two separate orders, a final order and an interim order, with respect to our recovery of gas costs.

The final order issued by the MPSC disallowed recovery of $6.2 million of actual natural gas costs we incurred during the past eight months. The MPSC also rejected a motion for reconsideration filed by us. We filed suit in district court on July 28, 2003, seeking to overturn the MPSC's decision to disallow recovery of these costs. Included in other current assets was $6.2 million, which was written off during June 2003 to comply with the final order. In the event the MPSC's decision is overturned, we will reinstate the asset.

The MPSC also granted an interim order on July 3, 2003, for the projected gas cost adjusted for a portion of the gas portfolio at a fixed price of $3.50 per MMBTU as opposed to the market price submitted in the original filing, which was higher. Assuming our average forecast price over the next six months occurs, the impact of this disallowance on the volumes at the imputed price compared to market price would be approximately $4.5 million for the period July 1, 2003 through June 30, 2004.

FERC

Through a filing with FERC in April 2000, we sought recovery of transition costs associated with serving two wholesale electric cooperatives. On July 15, 2002, a FERC administrative judge issued a summary judgment dismissing the company's claim primarily on the grounds that the filing did not use FERC methodology. On December 2, 2002, we filed a "Brief on Exceptions to the Initial Decision" aimed at reversing the initial decision. A decision by FERC was received on January 28, 2004, which affirmed the original summary judgment decision.

(19) (This Footnote was Intentionally Left Blank)

(20) (This Footnote was Intentionally Left Blank)

(21) Guarantees, Commitments and Contingencies

Qualifying Facilities Liability

With the acquisition of our Montana operations, we assumed a liability for expenses associated with certain Qualifying Facilities Contracts, or QFs. The QFs require us to purchase minimum amounts of energy at prices ranging from $65 to $138 per megawatt hour through 2029. Our gross contractual obligation related to the QFs is approximately $1.8 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates and payments from the MPSC, totaling approximately $1.4 billion through 2029. Upon completion of the purchase price allocation related to our acquisition of the electric and natural gas transmission and distribution business of The Montana Power Company, we established a liability of $134.3 million, based on the net present value (using an 8.75% discount factor) of the difference between our obligations under the QFs and the related amount recoverable. At December 31, 2003, the liability was $142.8 million.

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross obligation	Recoverable amounts	Net
2004	$ 54,823	($44,652)	$ 10,171
2005	56,579	(52,647)	3,932
2006	58,468	(52,681)	5,787
2007	60,634	(53,222)	7,412
2008	62,931	(53,750)	9,181
Thereafter	1,525,238	(1,138,340)	386,898
Total	$ 1,818,673	($1,395,292)	$ 423,381

Long Term Power Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply, electric generation construction and natural gas transportation contracts. These commitments range from one to 30 years. The commitments under these contracts as of December 31, 2003, were $251.0 million in 2004, $227.7 million in 2005, $165.0 million in 2006, $98.4 million in 2007, $45.3 million in 2008 and $448.5 million thereafter. These commitments are not reflected in our Financial Statements.

Environmental Liabilities

We are subject to numerous state and federal environmental regulations. Because laws and regulations applicable to our businesses are continually developing and are subject to amendment, reinterpretation and varying degrees of enforcement, we may be subject to, but can not predict with certainty the nature and amount of future environmental liabilities. The Clean Air Act Amendments of 1990 (the Act) stipulate limitations on sulfur dioxide and nitrogen oxide emissions from coal-fired power plants. We believe we can comply with such sulfur dioxide emission requirements at our generating plants and that we are in compliance with all presently applicable environmental protection requirements and regulations. We also are subject to other environmental statutes and regulations including those that related to former manufactured gas plant sites and other past and present operations and facilities. In addition, we may be subject to financial liabilities related to the investigation and remediation from activities of previous owners or operators of our industrial and generating facilities. The range of exposure for environmental remediation obligations at present is estimated to range between $43.9 million to $82.7 million.

During the third quarter of 2003, we engaged the services of an environmental consulting firm to perform a comprehensive evaluation of our historical and current utility operations and facilities. Based upon the results of the evaluation, we decreased our environmental reserve by $0.3 million. Our environmental reserve accrual is $4.9 million as of December 31, 2003. This reserve was established and adjusted during the current year in anticipation of future remediation activities at our Montana environmental sites and does not factor in any exposure arising from private tort actions or government claims for damages allegedly associated with specific environmental conditions.

Legal Proceedings

On September 14, 2003, we filed a voluntary petition for relief under the provisions of Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware under case number 03-12872 (CGC). We will continue to manage our properties and operate our business as a "debtor-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with Sections 1107(a) and 1108 of Chapter 11. As a result of the Chapter 11 filing, attempts to collect, secure or enforce remedies with respect to most prepetition claims against us are subject to the automatic stay provisions of Section 362(a) of Chapter 11. The description of our bankruptcy proceedings is summarized in Note 3, Chapter 11.

We are one of several defendants in a class action lawsuit entitled *McGreevey, et al. v. The Montana Power Company, et al*, now pending in federal court in Montana. The lawsuit, which was filed by the former shareholders of The Montana Power Company (most of whom became shareholders of Touch America Holdings, Inc. as a result of a corporate reorganization of The Montana Power Company), claims that the disposition of various generating and energy-related assets by The Montana Power Company were void because of the failure to obtain shareholder approval for the transactions. Plaintiffs thus seek to reverse those transactions, or receive fair value for their stock as of late 2001, when plaintiffs claim shareholder approval should have been sought. NorthWestern Corporation is named as a defendant due to the fact that we purchased Montana Power LLC, which plaintiffs claim is a successor to The Montana Power Company. We intend to vigorously defend against this lawsuit. On November 6, 2003, the Bankruptcy Court approved a stipulation between NorthWestern and the plaintiffs in *McGreevey, et al. v. The Montana Power Company, et al.* The stipulation provides that litigation, as against Northwestern, Clark Fork & Blackfoot LLC, the Montana Power Company, Montana Power LLC and Jack Haffey, shall be temporarily stayed for 180 days from the date of the stipulation. Pursuant to the stipulation and after providing notice to Northwestern, the plaintiffs may move the Bankruptcy Court for termination of the temporary stay. We cannot currently predict the impact or resolution of this litigation or reasonably estimate a range of possible loss, which could be material, and the resolution of this lawsuit may harm our business and have a material adverse impact on our financial condition or ability to timely confirm a plan of reorganization.

In NorthWestern Corporation vs. PPL Montana, LLC vs. NorthWestern Corporation and Clark Fork and Blackfoot, LLC, No. CV-02-94-BU-SHE, (D. MT), the Company is pursuing claims against PPL Montana, LLC due to its refusal to purchase the

Colstrip transmission assets which under the Asset Purchase Agreement ("APA") executed by and between The Montana Power Company ("MPC") and PP&L Global, Inc. ("PPL Global"), NorthWestern claims PPL Montana, LLC ("PPL") (PPL Global's successor-in-interest under the APA) is required to purchase the Colstrip transmission assets for $97.1 million. PPL has also asserted a number of counterclaims against NorthWestern and Clark Fork based in large part upon PPL's claim that MPC and/or NorthWestern Energy breached two Wholesale Transition Service Agreements and certain indemnification obligations under the APA in the approximate amount of $40 million. PPL also filed a proof of claim against NorthWestern's bankruptcy estate which assert substantially the same claims as the PPL counterclaim. PPL moved the Bankruptcy Court for relief from the automatic stay to pursue its counterclaims. NorthWestern objected to PPL's motion to lift the automatic stay and also filed a motion to transfer the venue of the entire litigation to the United States District Court for the District of Delaware. On March 19, 2004, the federal court in Montana denied our motion to transfer the entire case. We intend to vigorously defend against the PPL claims in the bankruptcy court and the counterclaims in federal court as well as vigorously prosecute our claims against PPL. We cannot currently predict the impact or resolution of the claims or this litigation or reasonably estimate a range of possible loss on the counterclaims, which could be material.

We are also one of several defendants in a class action lawsuit entitled *In Re Touch America ERISA Litigation*, which is currently pending in federal court in Montana. The lawsuit was filed by participants in the former Montana Power Company retirement savings plan and alleges that there was a breach of fiduciary duty in connection with the employee stock ownership aspects of the plan. The federal court has recently entered orders indefinitely staying the ERISA litigation because of Touch America Holdings Inc.'s bankruptcy filing. We intend to vigorously defend against these lawsuits. We cannot currently predict the impact or resolution of this litigation or reasonably estimate a range of possible loss, which could be material, and the resolution of this lawsuit may harm our business and have a material adverse impact on our financial condition or ability to timely confirm a plan of reorganization.

On August 12, 2003, the MCC filed a Petition for Investigation, Adoption of Additional Regulatory Controls and Related Relief with the MPSC. On August 22, 2003, the MPSC issued an order initiating an investigation of NorthWestern Energy relating to, among others, finances, corporate structure, capital structure, cash management practices, and affiliated transactions. The relief sought includes adoption of new regulatory controls that would specifically apply to NorthWestern, including additional reporting, cost allocation and financing rules and requirements, and examination of affiliate transactions necessary to ensure that we are not operating our energy division, and will not in the future operate, in a manner that would prejudice our ability to furnish reasonably adequate service and facilities at reasonable and just charges as required under Montana law. A procedural schedule was set in January 2004 with a hearing tentatively scheduled for June 2004. We cannot determine the impact or resolution of this petition, however, any action taken by the MPSC to increase the regulatory controls under which we operate may have a material affect on our liquidity, operations and financial condition. If we are unable to comply with any MPSC orders in a timely manner, then we may become subject to material monetary penalties and fines. We are working with the MCC to provide requested information in a timely manner, but we have reserved the right to contest whether this proceeding is stayed as a result of our bankruptcy filing.

We are also subject to various other legal proceedings and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these actions will not materially affect our financial position or results of operations or ability to timely confirm a plan of reorganization.

Sch. 19	MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Intangible Plant**			
2	2301 Organization	$12,876	$12,873	0.02%
3	2302 Franchises and Consents	114,169	114,169	-
4	2303 Miscellaneous Intangible Plant	521,586	387,091	34.75%
5	**Total Intangible Plant**	648,631	514,133	26.16%
6	2004			
7	**Underground Storage Plant**			
8	2350 Land and Land Rights	3,995,388	3,995,388	0.00%
9	2351 Structures and Improvements	2,845,364	2,725,874	4.38%
10	2352 Wells	7,782,699	7,750,184	0.42%
11	2353 Lines	6,525,844	6,360,120	2.61%
12	2354 Compressor Station Equipment	7,279,989	7,315,999	-0.49%
13	2355 Measuring & Regulating Equip.	1,995,005	1,762,740	13.18%
14	2356 Purification Equipment	223,171	223,171	0.00%
15	2357 Other Equipment	831,994	831,994	0.00%
16	**Total Underground Storage Plant**	31,479,454	30,965,470	1.66%
17				
18	**Transmission Plant**			
19	2365 Rights of Way	5,527,200	5,445,028	1.51%
20	2366 Structures and Improvements	8,807,540	9,116,481	-3.39%
21	2367 Mains	133,635,438	132,307,660	1.00%
22	2368 Compressor Station Equipment	17,720,360	17,560,600	0.91%
23	2369 Meas. & Reg. Station Equipment	10,574,293	10,001,536	5.73%
24	2370 Communication Equipment	21,616	-	-
24	2371 Other Equipment	82,052	75,670	8.43%
25	**Total Transmission Plant**	176,368,499	174,506,975	1.07%
26				
27	**Distribution Plant**			
28	2374 Land and Land Rights	874,556	874,556	0.00%
29	2375 Structures and Improvements	89,106	71,404	24.79%
30	2376 Mains	77,530,920	74,017,212	4.75%
31	2377 Compressor Station Equipment	-	-	-
32	2378 M&R Station Equip.-General	2,015,705	2,008,999	0.33%
33	2379 M&R Station Equip.-City Gate	-	-	-
34	2380 Services	52,916,670	52,626,128	0.55%
35	2381 Customers Meters and Regulators	26,772,261	18,987,886	41.00%
36	2382 Meter Installations	10,201,753	9,767,697	4.44%
37	2383 House Regulators	-	-	-
38	2384 House Regulator Installations	-	-	-
39	2385 M&R Station Equip.-Industrial	56,334	56,334	0.00%
40	2386 Other Prop. on Customers' Premises	-	-	-
41	2387 Other Equipment	-	-	-
42	**Total Distribution Plant**	170,457,305	158,410,216	7.60%

Sch. 19 cont.	**MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)**			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	**General Plant**			
3	2389 Land and Land Rights	101,675	101,675	-
4	2390 Structures and Improvements	684,305	684,305	0.00%
5	2391 Office Furniture and Equipment	1,164,688	1,273,902	-8.57%
6	2392 Transportation Equipment	4,389,480	4,717,141	-6.95%
7	2393 Stores Equipment	12,037	9,898	21.61%
8	2394 Tools, Shop & Garage Equipment	3,990,380	3,905,733	2.17%
9	2395 Laboratory Equipment	786,655	797,659	-1.38%
10	2396 Power Operated Equipment	1,531,113	1,621,166	-5.55%
11	2397 Communication Equipment	1,314,423	1,236,794	6.28%
12	2398 Miscellaneous Equipment	96,119	44,974	113.72%
13	2399 Other Tangible Property			-
14	**Total General Plant**	14,070,875	14,393,247	-2.24%
15	**Total Gas Plant in Service**	393,024,764	378,790,041	3.76%
16				
17	4101 Gas Plant Allocated from Common	27,218,466	26,165,336	4.02%
18	2105 Gas Plant Held for Future Use	4,990	8,984	-44.46%
19	2107 Gas Construction Work in Progress	3,043,347	3,483,979	-12.65%
20	2117 Gas in Underground Storage	39,706,740	40,347,982	-1.59%
21				
22				
23	**Total Gas Plant**	$462,998,307	$448,796,322	3.16%

Sch. 20	MONTANA DEPRECIATION SUMMARY - NATURAL GAS (INCLUDES CMP)				
	Functional Plant Class	Montana Plant Cost	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Production and Gathering	$ -	$ -	$ -	
4					
5					
6	Underground Storage	30,965,470	15,382,306	14,617,078	2.68%
7					
8	Other Storage				
9					
10	Transmission	174,299,788	62,626,128	60,128,398	1.78%
11					
12	Distribution	158,410,216	64,439,206	60,281,289	3.16%
13					
14	General and Intangible	14,703,125	8,173,016	7,567,331	8.46%
15					
16	Common	25,168,534	7,266,566	5,882,442	6.20%
17					
18	**TOTAL DEPRECIATION**	$403,547,133	$157,887,222	$148,476,538	2.69%
19					
20					
21					
22					
23					

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS		
Account Number & Title	This Year Cons. Utility	Last Year Montana	%Change
151 Fuel Stock			
152 Fuel Stock Expenses Undistributed			
153 Residuals			
154 Plant Materials & Operating Supplies			
Assigned and Allocated to:			
Operation & Maintenance			
Construction			
Storage Plant	$ 126,127	$ 131,596	-4.16%
Transmission Plant	706,648	739,648	-4.46%
Distribution Plant	682,964	681,683	0.19%
155 Merchandise			
156 Other Materials & Supplies			
157 Nuclear Materials Held for Sale			
163 Stores Expense Undistributed			
TOTAL MATERIALS & SUPPLIES	$1,515,739	$1,552,927	-2.39%

Sch. 22

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - GAS

	% Capital Structure	% Cost Rate	Weighted Cost
Commission Accepted - Most Recent 1/			
Docket Number: 2000.8.113			
Order Number : 6271c			
Common Equity	45.00%	10.75%	4.84%
Preferred Stock	6.97%	6.40%	0.45%
QUIPs Preferred	7.86%	8.54%	0.67%
Long Term Debt	40.17%	7.13%	2.86%
TOTAL	100.00%		8.82%

1/ Docket 2000.8.113, Order 627c specifies the authorized capital structure and associated costs for the regulated gas utility effective May 8, 2001.

Sch. 23

STATEMENT OF CASH FLOWS - 1/

	Description	This year	Last year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$34,301,745	$32,959,449	4.07%
4	Depreciation	52,444,146	50,433,581	3.99%
5	Amortization	3,737,096	3,129,978	19.40%
6	Amortization of Discount on LT Debt	279,770	324,433	-13.77%
7	Deferred Income Taxes - Net	42,140,019	(37,371,972)	212.76%
8	Investment Tax Credit Adjustments - Net	-	(12,717,931)	100.00%
9	Writedown for Utility Stipulation Agreement - Net	-	99,881,116	-100.00%
10	Writedown of Investments	-	412,500	-100.00%
11	Change in Operating Receivables - Net	(20,708,279)	2,776,114	>-300.00%
12	Change in Intercompany Receivables - Net	(125,843,337)	31,510,337	>-300.00%
13	Change in Materials, Supplies & Inventories - Net	164,886	3,214,845	-94.87%
14	Change in Operating Payables & Accrued Liabilities - Net	136,600,346	104,114,970	31.20%
15	Allowance for Funds Used During Construction (AFUDC)	(281,311)	(509,119)	44.75%
16	Change in Other Current Assets & Liabilities - Net	(24,271,232)	6,144,537	>-300.00%
17	Other Operating Activities:			
18	Undistributed Earnings from Subsidiary Companies	5,187,050	5,471,549	-5.20%
19	Other (net)	(62,241,794)	98,116,324	-163.44%
20	Change in Regulatory Assets	(723,947)	(93,050,012)	99.22%
21	Change in Regulatory Liabilities	(31,524,950)	(33,778,887)	6.67%
22	**Net Cash Provided by/(Used in) Operating Activities**	$9,260,208	$261,061,811	-96.45%
23	**Cash Inflows/Outflows From Investment Activities:**			
24	Construction/Acquisition of Property, Plant and Equipment	(44,744,506)	(52,472,205)	14.73%
25	(net of AFUDC & Capital Lease Related Acquisitions)			
26	Proceeds from Sale of Property, Plant and Equipment	-	8,312,695	-100.00%
27	Premium Paid by NorthWestern, Corp. for Utility Acquisition	-	(105,776,771)	
28	Contributions In and Advances to Affiliates	3,416,395	317,613	>300.00%
29	Other Investing Activities:			
30	Proceeds from Investments	19,132,574	145,676	>300.00%
31	Additional Investments	(532,358)	(884,185)	39.79%
32	Miscellaneous Special Funds	(825,857)	(67,197)	>-300.00%
33	**Net Cash Provided by/(Used in) Investing Activities**	(23,553,750)	(150,424,375)	84.34%
34	**Cash Flows from Financing Activities:**			
35	Proceeds from Issuance of:			
36	Long-Term Debt			
37	Members Capital Contribution in MP LLC	$0	500	-100.00%
38	Credit Facilities Borrowings, net	277,200,000		-
39	Dividends from Subsidiaries	-	-	-
40	Capital Financing	389,680	1,970,000	-80.22%
41	Net Increase in Short-Term Debt	-	-	-
42	Advance to Parent Company	(255,000,000)	(65,684,699)	-288.22%
43	Payment for Retirement of:			
44	Long-Term Debt	(15,000,000)	(13,003,479)	-15.35%
45	Preferred Stock	-	-	-
46	Capital Lease Obligations	(2,760,547)	(1,285,821)	-114.69%
47	Net Decrease in Short-Term Debt			
48	Dividends on Preferred Stock	-	(922,508)	100.00%
49	Dividends on Common Stock	-	-	-
50	Other Financing Activities	-	-	-
51	**Net Cash Provided by (Used in) Financing Activities**	4,829,133	(78,926,007)	106.12%
52	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(9,464,409)	$31,711,430	-129.85%
53	**Cash and Cash Equivalents at Beginning of Year**	$27,914,771	(3,796,659)	>300.00%
54	**Cash and Cash Equivalents at End of Year**	18,450,362	$27,914,771	-33.90%

56 1/ There were significant non-cash changes in the 2002 balance sheet related to our corporate reorganization and subsequent
57 divestiture and acquisition resetting equity under new ownership by NorthWestern Corporation. Additionally,
58 there were significant non-cash changes in regulatory asset and liability and other accounts for compliance with terms
59 in the stipulation agreement/TierII settlement. The cash flow presentation for 2002 is net of these non-cash changes.
60
61 The financial results reported include income taxes that are based upon NorthWestern's tax basis for plant assets purchased from
62 the Montana Power Company. This tax basis differs from amounts included in the most recently decided rate proceeding and
63 results in a lower deferred tax credit. This change was made in order to prevent any possible violation of the normalization
64 requirements of the federal income tax code. The change results in an increase in the reported rate base.

Sch. 24

LONG TERM DEBT 1/

Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
First Mortgage Bonds								
8.25% Series, Due 2007	12/05/91	02/01/07	55,000,000	54,550,100	364,979	8.260%	30,168	8.27%
8.95% Series, Due 2022	12/05/91	02/01/22	50,000,000	49,536,500	1,438,042	8.957%	129,981	9.04%
7.00% Series, Due 2005	03/01/93	03/01/05	50,000,000	49,375,000	5,380,236	7.075%	383,032	7.12%
7.30% Series, Due 2006	11/27/01	12/01/06	150,000,000	148,670,240	149,504,012	7.426%	11,289,296	7.55%
6.75% Credit Facility, Due 2006	12/17/02	12/01/06	280,000,000	258,103,495	274,400,000	6.750%	27,802,541	10.13%
Total First Mortgage Bonds			$585,000,000	$560,235,335	$431,087,269		$39,635,018	9.19%
Pollution Control Bonds								
6-1/8% Series, Due 2023	06/30/93	05/01/23	$90,205,000	$88,199,743	$88,905,504	5.841%	$5,604,532	6.30%
5.90% Series, Due 2023	12/30/93	12/01/23	80,000,000	79,040,800	79,358,592	6.428%	4,763,618	6.00%
Total Pollution Control Bonds			$170,205,000	$167,240,543	$168,264,096		$10,368,150	6.16%
Other Long Term Debt								
Quarterly Income Preferred Securities,								
8.45%, Series A (QUIPS) 2/	11/96	12/36	$ 65,000,000	$ 62,567,385	$ 65,000,000		$ 3,943,588	6.07%
Medium Term Notes-Secured Series	Various	Various	128,000,000	126,807,269	13,000,000		955,555	7.35%
Medium Term Notes-Unsecured Series B	Various	Various	115,000,000	113,851,197	39,844,335		3,058,306	7.68%
Cost Associated with Prior Debt Retirements	N/A	N/A	0	0	0		306,888	N/A
Total Other Long Term Debt			$308,000,000	$303,225,851	$117,844,335		$8,264,337	7.01%
TOTAL LONG TERM DEBT			$1,063,205,000	$1,030,701,729	$717,195,700		$58,267,505	8.12%

1/ Total Long-Term Debt does not include amounts due within 1 year - $2,800,000 at December 31, 2003.

2/ The Company believes and intends to take the position that the securities associated with the QUIPS issue will constitute indebtedness for United States federal income tax purposes. As such, the cost of QUIPS are deemed to be tax deductible. Since November 6, 2001, the Company has the right to wholly redeem the securities at any time, or partially redeem them from time to time.

SCHEDULE 25

PREFERRED STOCK

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2										
3										
4										
5										
6										
7	NOT APPLICABLE									
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	TOTAL									

Sch. 26

COMMON STOCK

	Avg. Number of Shares Outstanding 1/	Book Value Per Share 2/	Earnings Per Share 3/	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	37,396,762	($12.90)				$6.18	$5.02	
February	37,630,095	(13.24)				5.28	2.50	
March	37,630,095	(11.87)	$0.26			2.79	1.41	
April	37,680,095	(14.54)				2.62	1.65	
May	37,680,095	(15.26)				3.09	2.10	
June	37,680,095	(13.38)	(1.55)			2.85	1.96	
July	37,680,095	(13.55)				2.12	1.05	
August	37,680,095	(13.69)				1.23	0.51	
September	37,680,095	(14.78)	(1.41)			0.91	0.15	
October	37,680,095	(14.79)				0.32	0.15	
November	37,680,095	(14.93)				0.23	0.11	
December	37,680,095	(15.32)	(0.41)			0.16	0.08	
TOTAL Year End	37,648,151	($15.32)	($3.20)	$0.00	100.00%	$0.08		(0.0)

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for 2003.

2/ All Book Value Per Share amounts are based on actual shares and include unallocated stock held by Trustee for the Deferred Savings and Employee Ownership Plans.

3/ Quarterly Per Share amounts do not total to the annual Per Share amounts due to the effect of common stock issuances during the year.

As was stated in NorthWestern Corporation's 2003 Form 10-K, under anyplan of reorganization in the Chapter 11 proceedings, management of NorthWestern expects that there will be no value available for distribution to its common shareholders.

Sch. 27

MONTANA EARNED RATE OF RETURN - GAS

Account	Description	This Year	Last Year 3/	% Change
	Rate Base			
101	Plant in Service	$409,699,639	$400,622,418	2.27%
108	Accumulated Depreciation	(153,892,234)	(146,762,046)	-4.86%
	Net Plant in Service	$255,807,405	$253,860,372	0.77%
	Additions:			
154, 156	Materials & Supplies	$2,653,293	$3,184,918	-16.69%
165	Prepayments		0	-
	Other Additions	35,650,709	36,254,115	-1.66%
	Total Additions	$38,304,002	$39,439,033	-2.88%
	Deductions:			
190	Accumulated Deferred Income Taxes 1/	$5,635,733	($1,168,279)	>300.00%
252	Customer Advances for Construction	4,466,293	4,205,672	6.20%
255	Accumulated Def. Investment Tax Credits		0	-
	Other Deductions	31,043,229	32,758,433	-5.24%
	Total Deductions	$41,145,255	$35,795,826	14.94%
	Total Rate Base	$252,966,152	$257,503,579	-1.76%
	Net Earnings	$20,749,897	$27,526,647	-24.62%
	Rate of Return on Average Rate Base	8.203%	10.690%	-23.27%
	Rate of Return on Average Equity 2/	7.425%	12.207%	-39.17%
	Major Normalizing and Commission Ratemaking Adjustments			
	Rate Schedule Revenues	$1,975,873	($1,478,815)	233.61%
	Gas Cost Disallowance	7,812,372	0	-
	Inventory Receipts Adjustment	114,932	0	-
	CIS Project Write-Off	160,413	0	-
	Funding Trust Regulatory Liability	(430,040)	(17,322)	>-300.00%
	A & G Not Previously Allocated 4/	(3,713,657)	0	-
	Non-Allowables:			
	Advertising	44,884	145,210	-69.09%
	Benefit Restoration Plan	(315,621)	396,977	-179.51%
	Dues, Contributions, Other	12,400	4,224	193.56%
	Divestiture Related Expense	0	67,631	-100.00%
	Associated Income Taxes 5/	(4,275,303)	(1,740,155)	-145.69%
	Total Adjustments	$1,386,253	($2,622,250)	152.87%
	Revised Net Earnings	$22,136,150	$24,904,397	-11.12%
	Adjusted Rate of Return on Average Rate Base	8.751%	9.671%	-9.52%
	Adjusted Rate of Return on Average Equity 2/	10.035%	11.807%	-15.01%

1/ Includes adjustments related to FAS 109.

2/ Return on Equity calculated using the capital structure approved in Docket D2000.8.113.

3/ Amounts for 2002 have been adjusted to reflect the removal of the Natural Gas Funding Trust Regulatory Liability, in as much as the Trust itself is not reflected on this schedule.

4/ A & G expenses adjusted do not include any restructuring costs or amounts attributable to Nonutility operations.

5/ Associated Income taxes include an interest synchronization adjustment based upon the approved capital structure in Docket D2000.8.113.

The financial results reported include income taxes that are based upon NorthWestern's tax basis for plant assets purch from the Montana Power Company. This tax basis differs from amounts included in the most recently decided rate proceeding and results in a lower deferred tax credit. This change was made in order to prevent any possible violation of the normalization requirements of the federal tax code. The change results in an increase in the reported tax base.

Sch. 27 cont.

MONTANA EARNED RATE OF RETURN - GAS

	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset	$0	$0	-
4	Gas Stored Underground	33,279,559	33,393,972	-0.34%
5	Cost of Refinancing Debt	435,069	719,217	-39.51%
6	1997 and 1998 Severance Plans	41,884	41,884	0.00%
7	1999 Severance Plan	59,151	59,151	0.00%
8	ORCOM Development Costs	298,706	298,706	0.00%
9	SAP Development Costs	1,536,340	1,741,185	-11.76%
10				
11				
12	**Total Other Additions**	$35,650,709	$36,254,115	-1.66%
13				
14	**Detail - Other Deductions**			
15	Personal Injury and Property Damage	($2,720,334)	($1,227,107)	-121.69%
16	Storage Gas Sales 2000 & 2001	9,061,672	9,495,874	-4.57%
17	Gross Cash Requirements	6,445,766	6,043,980	6.65%
18	Met Life Refund	68,106	68,106	0.00%
19	Bond Refinancing CTC - GP	4,298,064	4,298,064	0.00%
20	Bond Refinancing CTC - RA	13,689,232	13,689,232	0.00%
21	USBC Gas	200,723	144,233	39.17%
22	Deferred Storage Gas Sales	0	246,051	-100.00%
23	**Total Other Deductions**	$31,043,229	$32,758,433	-5.24%
24				
25				
26				
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28				
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Sch. 28	MONTANA COMPOSITE STATISTICS - NATURAL GAS (INCLUDES CMP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	420,243,230
5	105	Plant Held for Future Use	4,990
6	107	Construction Work in Progress	3,043,347
7	117	Gas in Underground Storage	39,706,740
8	151-163	Materials & Supplies	1,515,739
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	$157,887,222
11	252	Contributions in Aid of Construction	4,285,448
12	**NET BOOK COSTS**		302,341,376
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	177,868,109
17			
18	**Total Operating Revenues**		177,868,109
19			
20	401-402	Other Operating Expenses	124,709,294
21	403-407	Depreciation & Amortization Expenses	11,786,418
22	408.1	Taxes Other than Income Taxes	15,937,102
23	409-411	Federal & State Income Taxes	4,685,398
24			
25	**Total Operating Expenses**		157,118,212
26	**Net Operating Income**		20,749,897
27			
28	415-421.1	Other Income	2,276,770
29	421.2-426.5	Other Deductions	1,760,676
30	**NET INCOME BEFORE INTEREST EXPENSE**		$21,265,992
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	142,181
34		Commercial	20,308
35		Industrial	152
36		Other	84
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		162,725
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	79.1
41		Average Annual Residential Cost per (Dkt)	$7.45
42		Average Residential Monthly Bill	$49.11
43			
44		Plant in Service (Gross) per Customer	$2,583

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	462	80		542
2	Amsterdam	727				-
3	Anaconda	9,417	3,364	341	7	3,712
4	Augusta	284	190	41	1	232
5	Barber					-
6	Belfry	219	5			5
7	Belgrade	5,728	3,906	500	3	4,409
8	Big Mountain		131	28		159
9	Big Sandy	703	302	71		373
10	Big Sky	1,221				-
11	Big Timber	1,650	894	187		1,081
12	Bigfork	1,421	920	155		1,075
13	Billings	89,847	12	5	2	19
14	Bonner	1,693	77	5		82
15	Boulder	1,300	470	80	1	551
16	Bozeman	27,509	15,573	2,375	21	17,969
17	Browning	3,877	1,104	174	2	1,280
18	Buffalo		5			5
19	Butte	33,892	12,631	1,367	19	14,017
20	Cardwell	40	17	5		22
21	Carter	62	30	10		40
22	Chester	871	374	117	1	492
23	Chinook	1,386	723	145		868
24	Choteau	1,802	845	176	4	1,025
25	Churchill		25	4		29
26	Clancy	1,406	1,239	82	2	1,323
27	Clinton		369	18		387
28	Columbia Falls	3,645	2,949	327	7	3,283
29	Columbus	1,748	989	159	5	1,153
30	Conrad	2,753	1,137	218	2	1,357
31	Coram	337	112	23		135
32	Corvallis	443	944	93		1,037
33	Cut Bank	3,105	45	15	5	65
34	Deer Lodge	3,421	1,583	209	6	1,798
35	Dillon	3,752	1,966	337	5	2,308
36	Drummond	318	213	59		272
37	East Glacier	396	123	42	1	166
38	East Helena	1,642	1,837	108	2	1,947
39	Elliston	225	96	13		109
40	Essex		70	15		85
41	Fairfield	659	411	88	1	500
42	Florence	901	1,056	72		1,128
43	Floweree		46	8		54
44	Fort Belknap	1,262	354	55		409
45	Fort Benton	1,594	626	156	1	783
46	Fort Harrison			61	1	62
47	Fort Shaw	274	104	13		117
48	Galata		3			3
49	Gallatin Gateway		154	31		185
50	Garneill		9	1		10
51	Garrison	112	24	4		28
52	Gildford	185	79	30		109

Sch. 29

Montana Customer Information- Natural Gas, 1/

	City	Population Census 2000				Total
1	Gransdale		23	2		25
2	Great Falls	56,690	950	50	1	1,001
3	Greycliff	56	42	4		46
4	Hall		60	13		73
5	Hamilton	3,705	3,546	628	6	4,180
6	Harlem	848	334	74	1	409
7	Harlowtown	1,062	542	101	3	646
8	Havre	9,621	4,528	628	7	5,163
9	Helena	45,819	15,455	2,228	29	17,712
10	Hingham	157	85	26		111
11	Hungry Horse	934	264	36		300
12	Inverness	103	39	14		53
13	Jefferson City	295	123	13	2	138
14	Joplin	210	96	28		124
15	Judith Gap	164	64	15		79
16	Kalispell	14,223	10,016	1,806	16	11,838
17	Kremlin	126	49	16		65
18	Laurel	6,255	11		2	13
19	Ledger		6			6
20	Lewistown	6,178	2,876	476	6	3,358
21	Livingston	7,348	3,714	535	6	4,255
22	Logan		2			2
23	Lohman		2	1		3
24	Lolo	3,388	1,354	84		1,438
25	Loma	92	38	19		57
26	Manhattan	1,396	1,100	140		1,240
27	Martin City	331	118	16		134
28	Milltown		76	8		84
29	Missoula	57,053	26,900	3,460	33	30,393
30	Moore	186	2	1		3
31	Philipsburg	914	431	76		507
32	Ramsay		38	7		45
33	Red Lodge	2,177	1,572	262	1	1,835
34	Reedpoint	185	107	18		125
35	Roberts		148	21		169
36	Rocker		13	7		20
37	Rudyard	275	134	29	1	164
38	Ryegate		3			3
39	Shawmut		23	4		27
40	Shelby	3,216	9	3	2	14
41	Sheridan	659	373	66		439
42	Silver Star		22	5		27
43	Silver Bow		3	2	2	7
44	Simms	373	157	16		173
45	Somers	556	249	22		271
46	Springdale		2			2
47	Stevensville	1,553	1,428	228		1,656
48	Sun River	131	110	18		128
49	Sunburst				1	1
50	Three Forks	1,728	778	127	7	912
51	Townsend	1,867				-
52	Trident		2			2

Montana Customer Information- Natural Gas, 1/

	City	Population Census 2000				Total
1	Turah		85	1		86
2	Twin Bridges	400	211	52		263
3	Valier	498	312	75	1	388
4	Vaughn	701	337	26		363
5	Victor	859	459	69		528
6	Warm Springs				1	1
7	West Glacier		105	41		146
8	Whitefish	5,032	3,242	452	6	3,700
9	Whitehall	1,044	667	115	3	785
10	Whitlash		2			2
11	Willow Creek	209	94	13		107
12	Williamsburg		1			1
13	Wolf Creek		51	28		79
14	**Total**	451,678	142,181	20,308	236	162,725

1/ Customer populations represent an average of the 12 month period from 01/01/03 through 12/31/03.

Sch. 30

MONTANA EMPLOYEE COUNTS

Department	Year Beginning 1/	Year End 1/	Average
Utility Operations			
Executive	2	1	2
Financial, Risk Mgmt. & Information Services	113	120	117
Human Resources & Administration	36	33	34
Utility Services & Division Administration	655	620	637
Business Development & Regulatory Affairs	25	24	24
Transmission	168	150	159
Legal	5	5	5
TOTAL EMPLOYEES	1,004	953	978

1/ Part time employees have been converted to full time equivalents.

Sch. 31	MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	Rainbow-Canyon Ferry Taps Line Reconductoring	$1,030,000	$1,030,000
5	Electric Transmission Circuit Upgrades	1,130,000	1,130,000
6			
7			
8			
9	All Other Projects < $1 Million Each	29,686,227	29,686,227
10			
11	**Total Electric Utility Construction Budget**	31,846,227	31,846,227
12			
13	**Natural Gas Operations**		
14			
15			
16			
17			
18	All Other Projects < $1 Million Each	7,805,557	7,805,557
19			
20	**Total Natural Gas Utility Construction Budget**	7,805,557	7,805,557
21			
22	**Common**		
23			
24	All Other Projects < $1 Million Each	5,089,868	5,089,868
25	(Includes IS, Communications, Facillities, Cust Serv)		
26			
27			
28	**Total Common Utility Construction Budget**	5,089,868	5,089,868
29			
30	CU4 Saddle Dam Repair	1,012,000	1,012,000
31			
32	All Other Projects < $1 Million Each	3,128,276	3,128,276
33			
34			
35			
36	**Total Colstrip Unit 4 Construction Budget**	4,140,276	4,140,276
37	**TOTAL CONSTRUCTION BUDGET**	$48,881,928	$48,881,928

TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS

Transmission System-Sales and Transportation

Month	Peak Day of Month		Peak Day Volume (MMBTU's)		Monthly Volumes (MMBTU's)	
	Total Company	Montana	Total Company	Montana	Total Company, 2/	Montana, 3/
January					6,277,391	4,261,147
February					5,909,377	3,190,542
March					5,736,185	2,663,184
April		NOT AVAILABLE 1/			3,072,524	3,412,867
May					2,958,923	2,810,208
June					2,085,344	3,442,452
July					1,684,831	2,236,059
August					1,744,386	1,765,506
September					2,147,538	1,743,945
October					3,045,614	2,233,639
November					4,943,027	4,109,848
December					5,101,315	4,694,115
TOTAL					44,706,455	36,563,512

Distribution System-Sales and Transportation

Month	Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
	Total Company	Montana	Total Company	Montana	Total Company, 4/	Montana, 5/
January	2,971,540		364,748		3,336,288	2,971,540
February	2,642,237		373,593		3,015,830	2,642,237
March	2,762,254		351,786		3,114,040	2,762,254
April	1,702,203		330,239		2,032,442	1,702,203
May	1,295,002		252,941		1,547,943	1,295,002
June	721,879		211,025		932,904	721,879
July	481,168		145,695		626,863	481,168
August	363,193		145,695		508,888	363,193
September	458,666		304,683		763,349	458,666
October	779,907		358,511		1,138,418	779,907
November	1,818,634		367,962		2,186,596	1,818,634
December	2,851,055		379,781		3,230,836	2,851,055
TOTAL	18,847,738		3,586,659		22,434,397	18,847,738

Storage System-Sales and Transportation

Month	Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
	Total Company	Montana	Total Company 4/		Montana 5/	
	1/	1/	Injection	Withdrawal	Injection	Withdrawal
January			5,294	3,065,396		774,723
February			1,368	3,327,639		1,473,199
March			4,252	2,672,484		1,480,138
April			617,955	337,370	167,433	
May			1,107,943	207,924	640,461	
June			1,631,578	110,186	1,305,383	
July			1,981,035	125,629	1,098,091	
August			1,673,909	226,585	870,167	
September			1,178,633	182,151		266,643
October			2,209,108	268,720		854,676
November			48,911	1,349,722		536,075
December			7,666	1,624,149		612,888
TOTAL			10,467,652	13,497,955	4,081,535	5,998,342

1/ Data is not accumulated on a daily basis, therefore the peak day and peak day volumes are not available.
2/ Includes intrastate and interstate deliveries.
3/ Includes intrastate deliveries only.
4/ Includes sales and transportation volumes. Losses of gas are not available.
5/ Includes sales volumes only. Losses of gas are not available.

Sch. 33	SOURCES OF CORE NATURAL GAS SUPPLY				
	Name of Supplier	Last Year Volumes MMBTU	This Year Volumes MMBTU	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2	Canadian Pipeline	201,000		$1.6555	
3	Havre Pipeline	1,622,212		3.0561	
4	Pan Canadian Pipeline	9,609,274		2.3248	
5	Colorado Interstate Pipeline	1,265,490		25.4041	
6	Intra Montana Purchase	7,635,678		2.5684	
7	**TOTAL CORE SUPPLY LAST YEAR**	20,333,654	0	$2.4729	
8					
9	Canadian Pipeline		(3,569,868)		($4.3590)
10	Havre Pipeline		5,440,529		4.8710
11	Pan Canadian Pipeline		6,072,960		4.8250
12	Colorado Interstate Pipeline		1,412,472		4.3680
13	Intra Montana Purchase		8,946,592		4.4680
14	**TOTAL CORE SUPPLY THIS YEAR**		18,302,685		$4.7180
15					
16	Note: This year's volumes reflect the net amount of volumes procured from the named supplier less				
17	volumes sold to that supplier.				
18					

Sch. 34 MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS - NATURAL GAS 1/ & 2/

NorthWestern Energy
Natural Gas Utility
2003 USBC Revenues

	USBC DKT	Unit USBC Rate	% of USB Revenue By Class
Residential			
Residential	12,457,102	$ 0.050000	40%
General Service			
Commercial	6,390,637	$ 0.050000	20%
On-System Transportation			
Core/Tier 2	2,111,096	$ 0.050000	7%
Tier 1	10,548,474	$ 0.026000	33%
Total USBC	**31,507,308**		**100%**
Total USBC Revenues	**$1,320,766**		

Universal System Benefits Program Results

USB Categories	2003 Natural Gas Revenue Allocation	Spent in 2003	Allocation less Expenses
Local Conservation	**327,000**	**326,427**	**573**
E+ Residential Audit		300,037	
NWE Promotion		12,281	
NWE Labor		14,096	
NWE Admin. Non-labor		13	
Local Conservation Summary		326,427	
Low Income	**993,766**	**1,194,562**	**(200,796)**
Bill Assistance		595,003	
Free Weatherization		585,000	
NWE Promotion		114	
NWE Labor		14,332	
NWE Admin. Non-labor		113	
Low Income Summary		1,194,562	
Totals	**1,320,766**	**1,520,989**	**(200,223)**
2003 USB Revenues less Expenses*			**(200,223)**

USB Expenditure Summary and Savings Estimate

USB Category	Allocation of 2003 Natural Gas USB	Percentage by Category	Estimated Savings (DKT)
Local Conservation	326,427	21%	14,176
Low Income	1,194,562	79%	11,688
	1,520,989	**100%**	**25,865**

2003 Gas USB Customer/Project Summary

Residential Onsite Audits	588
Bill Assistance	7,231
Free Weatherization	504

Sch. 35	MONTANA CONSUMPTION AND REVENUES - NATURAL GAS						
		Operating Revenues 1/		Dkt Sold		Average Customers	
	Description	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Sales of Natural Gas						
2							
3	Residential	$ 83,799,757	$ 66,849,740	11,247,832	13,292,960	142,181	137,410
4	Commercial	41,252,904	32,482,211	5,501,961	6,454,687	20,308	19,651
5	Industrial Firm	1,383,887	1,108,269	193,598	237,116	152	155
6	Public Authorities	284,199	96,983	37,881	13,399	17	17
7	Interdepartmental	331,871	270,611	47,826	57,691	49	51
8	CNG Station	2,971	7,591	-	-	-	-
9	Sales to Other Utilities 2/	31,652,646	735,162	190,819	246,354	18	18
10	TOTAL SALES	158,708,235	101,550,566	17,219,917	20,302,206	162,725	157,302
11		Operating Revenues		Dkt Transported		Average Customers	
12		Current	Previous	Current	Previous	Current	Previous
13		Year	Year	Year	Year	Year	Year
14	Transportation of Gas						
15							
16	Firm - DBU	$ (165,767)	$ (517,609)	3,117,318	3,277,484	207	210
17	Firm - TBU	8,906,571	8,119,538	10,484,470	11,893,841	19	17
18	Firm Storage	1,934,469	1,632,434	-	-	-	-
19	Interruptible - DBU	17,524	14,174	352,296	337,938	5	8
20	Interruptible - TBU	913,451	1,032,857	3,290,791	3,909,884	2	2
21	Interruptible - Off System	718,255	1,923,245	6,739,590	6,959,129	13	13
22							
23							
24							
25							
26							
27							
28	Storage - Off System	555,235	1,246,273	-	-		
29							
30	**TOTAL TRANSPORTATION**	$ 12,879,738	13,450,912	23,984,465	26,378,276	246	250
31							

32 1/ Does not included unbilled or Canadian Montana Pipeline Corporation revenues.

33

34 2/ In 2003, NorthWestern entered into approximately 3.3 bcf of fixed price natural gas contracts to hedge customer price risk during
35 the 2003-2004 winter season. These fixed price contracts at the AECO hub systematically offset medium-term on-system supply,
36 which are purchased from a third party on NorthWestern's system at a floating daily index price. Other sales were conducted due
37 to excess supply on system or exchanges for in-ground storage from customers. All purchases and sales were conducted as
38 regulated activity for the Montana customers and such net cost will be recovered in rates.