YEAR ENDING 2005

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

Gas Annual Report

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Sch. 1

IDENTIFICATION

Legal Name of Respondent:	NorthWestern Corporation
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:	Kendall Kliewer
Telephone Number for Report Inquiries:	(406) 497-2759
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.

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
	See Northwestern Corporation's Annual Report on Form 10-K to the SEC for the Corporate Board of Directors.	

Sch. 3	OFFICERS	
Title	Department Supervised	Name
President & Chief Executive Officer	Executive	Michael Hanson
Vice President, Chief Financial Officer	Tax, Internal Audit & Controls Financial Planning & Analysis Controller & Treasury Functions Investor Relations	Brian Bird
Vice President, General Counsel & Corporate Secretary	Legal	Thomas Knapp
Vice President, Information Technology	IT Applications & Infastructure Client Services IT Asset & Business Telecommunications	Bart Thielbar
Vice President, Retail Operations	Distribution Planning, Operations & Maintenance Distribution Engineering & Performance General Construction & Maintenance Natural Gas Marketing	Curt Pohl
Vice President, Wholesale Operations	Energy Supply Operations Transmission Operations	David Gates
Vice President, Regulatory & Governmental Affairs	Regulatory Affairs State, Local & Community Relations Labor Relations	Patrick Corcoran
Vice President, Administrative Services	Utility Services, Operations Support Safety/Health/Environmental Human Resources Records Management	Greg Trandem
Vice President, Customer Care & Communications	Revenue Collections Call Center Systems Infastructure & Support Customer/Supplier Relations Communications	Bobbi Schroeppel
Internal Audit & Controls Officer	Internal Audit Enterprise Risk	Michael Nieman
Controller	Financial/SEC Reporting Accounting Fixed Assets Accounts Payable	Kendall Kliewer
Treasurer	Treasury Functions Risk Management	Paul Evans
Assistant Treasurer	Cash Management	Emilie Ng

Reflects active officers as of December 31, 2005.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 59,447**	**99.97%**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Wholesale Electric Natural Gas Utility Natural Gas Pipeline Propane Utility Natural Gas Funding Trust - (Bond Transition Financing) 1/		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Unregulated Operations		**$ 20**	**0.03%**
Direct Subsidiaries:			
NorthWestern Services Corporation	Nonregulated natural gas marketing, natural gas pipeline company, HVAC services property management		
Clarkfoot and Blackfoot, LLC	Milltown hydroelectric facility		
NorthWestern Investments, LLC	Investment Corporation		
Risk Partners Assurance, Ltd.	Captive insurance company		
Indirect Subsidiaries:			
NorthWestern Energy Development, LLC	Non-regulated energy interest		
NorthWestern Generation I, LLC	Holds interest in MT Megawatts I, LLC		
Montana Megawatts I, LLC	Interest in MT First Megawatts project		
NorthWestern Energy Marketing, LLC	Non-regulated energy marketing		
Nekota Resources Inc.	Non-regulated intrastate natural gas pipeline		
Netexit, Inc.	Discontinued communications services		
Blue Dot Services, LLC	Discontinued HVAC services		
Total Corporation		**$ 59,467**	**100.00%**

1/ While the Natural Gas Funding Trust (the Trust) is regulated by the MPSC and information pertaining to the Trust is reported to the MPSC on a semi-annual basis, it is reflected on the equity basis in this presentation.

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Utility Administration Executive Department	Includes the following departments: CEO; COO; Corp Aircraft	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	$5,916,754	69.85%	$2,553,903
Legal Department	Includes the following departments: Chief Legal, Insurance	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	$7,668,136	65.30%	$4,074,308
Communications &Human Resources	Includes the following departments: Human Resources; Benefits Admin.; Compensation & Labor Relations; Employment; Payroll	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	25,460,401	88.01%	3,468,901
Finance / Accounting	Includes the following departments: CFO Treasury, FP&A, Controller, Fixed Assets, Accounting; Tax & Financial Reporting, Investor Relations	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	7,725,550	70.67%	3,205,638
Administrative	Includes the following departments: Administrative; Mailing Services & Printing Services, Records Mgmt	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	2,106,097	69.85%	909,074
Information Technology	Includes the following departments: IT Sr; VP/CIO; IT Applications Infrastructure, Licensing & Leasing	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	6,557,056	69.85%	2,830,283
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research Government Affairs, Reg Support Services, Community Relations	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	3,222,432	79.60%	825,819
Customer Care	Includes the following departments: Customer Care Common, Customer Care Combined, Customer Care MT Only	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	13,056,481	72.21%	5,025,978
Audit & Controls	Includes the following departments: Audit and Controls, Internal Auditing Project Office, Business Continuity	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on a % developed using plant, revenues and operating labor.	774,918	69.85%	334,485
TOTAL			$72,487,825	75.73%	$23,228,389

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

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						
4						
5						
6	Unit 4 - Lease Management	Purchased Power	Market Rates	$40,155,422	37.82%	$40,155,422
7						
8						
31						
32	TOTAL Nonutility Subs			$40,155,422		$40,155,422
33	Total Nonutility Subs Revenues			$106,178,322		
34						
35	Utility Subsidiaries					
36	Total Utility Subsidiaries					
37	Total Utility Sub Revenues			$3,755,447		
38	TOTAL AFFILIATE TRANSACTIONS			$40,155,422		$40,155,422

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						
4	Colstrip Unit 4 Lease Management Wheeling			$311,550	0.43%	$311,550
5						
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$311,550		$311,550
10	**Total Nonutility Subsidiaries Expenses**			$72,318,023		
11						
12						
13	**Utility Subsidiaries**					
14	Canadian Montana Pipeline Gas Transportation			$12,160	1.14%	$12,160
15	**Total Utility Subsidiaries**			$12,160		$12,160
16	**Total Utility Subsidiaries Expenses**			$1,068,589		
17	**TOTAL AFFILIATE TRANSACTIONS**			$323,710		$323,710

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
1						
2	400 Operating Revenues	$ 356,196,417	$ 110,656,618	$ 245,539,799	$ 219,456,415	11.89%
3						
4	**Total Operating Revenues**	356,196,417	110,656,618	245,539,799	219,456,415	11.89%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	291,601,666	110,567,954	181,033,712	165,779,000	9.20%
9	402 Maintenance Expense	4,723,385	977,844	3,745,541	3,763,014	-0.46%
10	403 Depreciation Expense	14,797,497	3,833,533	10,963,964	10,740,800	2.08%
11	404-405 Amort. & Depletion of Gas Plant	2,215,392	797,116	1,418,276	1,307,992	8.43%
12	406 Amort. of Plant Acquisition Adj.	(2,288,552)	(2,288,552)	-	-	-
13	407.3 Regulatory Amortizations - Debit	4,495,335	372,341	4,122,994	2,444,241	68.68%
14	407.4 Regulatory Amortizations - Credit	(2,834,490)	-	(2,834,490)	(4,033,530)	29.73%
15	408.1 Taxes Other Than Income Taxes	23,143,669	2,623,354	20,520,315	15,518,177	32.23%
16	409.1 Income Taxes-Federal	(9,183,879)	(11,516,143)	2,332,264	1,349,379	72.84%
17	-Other	(292,181)	(603,520)	311,339	(114,536)	>300.00%
18	410.1 Deferred Income Taxes-Dr.	54,519,175	6,708,218	47,810,957	35,103,582	36.20%
19	411.1 Deferred Income Taxes-Cr.	(42,671,953)	-	(42,671,953)	(31,044,434)	-37.45%
20	411.4 Investment Tax Credit Adj.	(192,656)	(192,656)	-	-	-
21						
22	**Total Operating Expenses**	338,032,408	111,279,489	226,752,919	200,813,685	12.92%
23	**NET OPERATING INCOME**	$ 18,164,009	$ (622,871)	$ 18,786,880	$ 18,642,730	0.77%

This financial statement is 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. As such, in accordance with FERC requirements, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corporation.

Sch. 9	MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
2	**Core Distribution Business Units**					
3	**(DBUs)**					
4	440 Residential	$ 199,817,061	$ 64,424,049	$ 135,393,012	$ 115,544,919	17.18%
5	442.1 Commercial	110,981,032	43,962,655	67,018,377	56,904,414	17.77%
6	442.2 Industrial Firm	2,036,824	-	2,036,824	1,798,428	13.26%
7	445 Public Authorities	548,958	-	548,958	436,789	25.68%
8	448 Interdepartmental Sales	493,597	-	493,597	442,228	11.62%
9	491.2 CNG Station	-	-	-	3,346	-100.00%
11	**Total Sales to Core DBUs**	313,877,472	108,386,704	205,490,768	175,130,124	17.34%
13	447 Sales for Resale	20,408,269	-	20,408,269	25,970,466	-21.42%
15	**Total Sales of Natural Gas**	20,408,269	-	20,408,269	25,970,466	-21.42%
17	**Transportation**					
19	489 Transportation (inc. CMP)	17,830,821	1,611,655	16,219,166	15,221,505	6.55%
20	495 Off System Storage	7,071	-	7,071	82,868	-91.47%
22	**Total Revenues From Transportation**	17,837,892	1,611,655	16,226,237	15,304,373	6.02%
24	**Other Operating Revenue**					
26	Miscellaneous Revenues	4,072,784	658,259	3,414,525	3,051,452	11.90%
28	**Total Other Operating Revenue**	4,072,784	658,259	3,414,525	3,051,452	11.90%
29	**TOTAL OPERATING REVENUE**	$ 356,196,417	$ 110,656,618	$ 245,539,799	$ 219,456,415	11.89%
32	Sales for Resale reported on line 13 represents on and off-system sales from excess supply.					
33	Revenues generated from these sales flow back to customers as a credit to gas cost expense.					

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	**Gas Raw Materials**					
2	**Gas Raw Materials-Operation**					
3	735 Miscellaneous Production Expenses	$ 36,412	$ 36,412	$ -	$ -	-
4	**Total Operation-Gas Raw Materials**	$ 36,412	$ 36,412	-	-	-
5						
6	**Gas Raw Materials-Maintenance**					
7	741 Structures & Improvements	$ 44,781	$ 44,781	-	-	-
8	**Total Maintenance-Gas Raw Materials**	$ 44,781	$ 44,781	-	-	-
9	**Total Gas Raw Materials**	$ 81,193	$ 81,193	-	-	-
10	**Production Expenses**					
11						
12	**Production & Gathering-Operation**					
13	750 Supervision & Engineering	-	-	-	-	-
14	751 Maps & Records	-	-	-	-	-
15	752 Gas Wells Expenses	-	-	-	-	-
16	753 Field Lines Expenses	-	-	-	-	-
17	754 Field Compressor Station Expense	-	-	-	-	-
18	755 Field Comp. Station Fuel & Power	-	-	-	-	-
19	756 Field Meas. & Reg. Station Expense	-	-	-	-	-
20	757 Dehydration Expense	-	-	-	-	-
21	758 Gas Well Royalties	-	-	-	-	-
22	759 Other Expenses	-	-	-	-	-
23	760 Rents	-	-	-	-	-
24	**Total Oper.-Production & Gathering**	-	-	-	-	-
25						
26	**Other Gas Supply Expense-Operation**					
27	800 NG Wellhead Purchases	207,400,684	-	207,400,684	153,703,809	34.94%
28	800 NG Wellhead Purchases, Non-physica	(38,797,894)	-	(38,797,894)	(35,057,600)	-10.67%
29	803 NG Transmission Line Purchases	245,285	-	245,285	766,712	-68.01%
30	805 Other Gas Purchases	77,598,812	90,263,542	(12,664,730)	11,145,620	-213.63%
31	805 Purchased Gas Cost Adjustments	-	-	-	-	-
32	805 Incremental Gas Cost Adjustments	-	-	-	-	-
33	805 Deferred Gas Cost Adjustments	-	-	-	-	-
34	806 Exchange Gas	-	-	-	-	-
35	807 Well Expenses-Purchased Gas	1,103,517	-	1,103,517	345,368	219.52%
36	807 Purch. Gas Meas. Stations-Oper.	-	-	-	-	-
37	807 Purch. Gas Meas. Stations-Maint.	-	-	-	-	-
38	807 Purch. Gas Calculations Expenses	-	-	-	-	-
39	808 Other Purchased Gas Expenses	-	-	-	-	-
40	808 Gas Withdrawn from Storage -Dr.	(11,573,110)	-	(11,573,110)	(732,614)	>-300.00%
41	809 Gas Delivered to Storage -Cr.	-	-	-	-	-
42	810 Gas Used-Comp. Station Fuel-Cr.	-	-	-	-	-
43	811 Gas Used-Products Extraction-Cr.	-	-	-	-	-
44	812 Gas Used-Other Utility Oper.-Cr.	-	-	-	-	-
45	813 Other Gas Supply Expenses	-	-	-	-	-
46	**Total Other Gas Supply Expenses**	235,977,294	90,263,542	145,713,752	130,171,295	11.94%
47	**Total Production Expenses**	235,977,294	90,263,542	145,713,752	130,171,295	11.94%

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	24,509	-	24,509	68,104	-64.01%
5	815 Maps & Records	-	-	-	221	-100.00%
6	816 Wells	173,279	-	173,279	165,060	4.98%
7	817 Lines	8,967	-	8,967	21,738	-58.75%
8	818 Compressor Station	300,207	-	300,207	310,069	-3.18%
9	819 Compressor Station Fuel & Power	-	-	-	-	-
10	820 Measuring & Regulating Station	19,160	-	19,160	18,498	3.58%
11	821 Purification	56,119	-	56,119	71,295	-21.29%
12	824 Other Expenses	83,310	-	83,310	98,065	-15.05%
13	825 Storage Well Royalties	125,557	-	125,557	100,227	25.27%
14	826 Rents	-	-	-	-	-
15	**Total Operation-Underground Storage**	791,108	-	791,108	853,277	-7.29%
16						
17	**Underground Storage-Maintenance**					
18	830 Supervision & Engineering	-	-	-	-	-
19	831 Structures & Improvements	17,645	-	17,645	9,012	95.80%
20	832 Reservoirs & Wells	6,812	-	6,812	5,733	18.82%
21	833 Lines	14,156	-	14,156	26,033	-45.62%
22	834 Compressor Station Equipment	82,799	-	82,799	79,193	4.55%
23	835 Meas. & Reg. Station Equipment	10,714	-	10,714	7,660	39.86%
24	836 Purification Equipment	18,547	-	18,547	22,233	-16.58%
25	837 Other Equipment	10,954	-	10,954	14,423	-24.05%
26	**Total Maintenance-Underground Storage**	161,627	-	161,627	164,287	-1.62%
27	**Total Underground Storage Expenses**	952,735	-	952,735	1,017,564	-6.37%
28	**Transmission Expenses**					
29	**Transmission-Operation**					
30	850 Supervision & Engineering	1,749,517	-	1,749,517	1,979,463	-11.62%
31	851 System Control & Load Dispatching	501,376	-	501,376	506,374	-0.99%
32	853 Compressor Station Labor & Expense	706,326	-	706,326	686,637	2.87%
33	855 Other Fuel & Power for Comp. Stat.	-	-	-	-	-
34	856 Mains	780,453	-	780,453	704,596	10.77%
35	857 Measuring & Regulating Station	669,088	-	669,088	592,080	13.01%
36	858 Transmission & Comp.-By Others	-	-	-	-	-
37	859 Other Expenses	1,077,105	-	1,077,105	1,495,504	-27.98%
38	860 Rents	-	-	-	-	-
39	**Total Operation-Transmission**	5,483,865	-	5,483,865	5,964,654	-8.06%
40	**Transmission-Maintenance**					
41	861 Supervision & Engineering	-	-	-	-	-
42	862 Structures & Improvements	229,394	-	229,394	261,959	-12.43%
43	863 Mains	431,715	-	431,715	421,991	2.30%
44	864 Compressor Station Equipment	300,621	-	300,621	367,254	-18.14%
45	865 Meas. & Reg. Station Equipment	251,284	-	251,284	250,956	0.13%
46	867 Other Equipment	12,222	-	12,222	19,269	-36.57%
47	**Total Maintenance-Transmission**	1,225,236	-	1,225,236	1,321,429	-7.28%
48	**Total Transmission Expenses**	6,709,101	-	6,709,101	7,286,083	-7.92%

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	1,920,222	824,604	1,095,618	777,801	40.86%
4	871 Load Dispatching	71,707	71,707	-	-	-
5	872 Compressor Station Labor & Expense	-	-	-	219	-100.00%
6	873 Compressor Station Fuel and Power	-	-	-	-	-
7	874 Mains and Services	2,888,541	1,216,562	1,671,979	1,505,176	11.08%
8	875 Meas. & Reg. Station-General	188,122	71,455	116,667	78,630	48.37%
9	876 Meas. & Reg. Station-Industrial	-	-	-	850	-100.00%
10	877 Meas. & Reg. Station-City Gate	4,036	3,944	92	3,509	-97.36%
11	878 Meter & House Regulator	1,654,828	597,001	1,057,827	790,843	33.76%
12	879 Customer Installations	2,652,101	169,643	2,482,458	1,980,430	25.35%
13	880 Other Expenses	1,860,182	1,136,686	723,496	2,202,489	-67.15%
14	881 Rents	3,519	-	3,519	17,177	-79.52%
15	**Total Operation-Distribution**	11,243,258	4,091,602	7,151,656	7,357,124	-2.79%
16	**Distribution-Maintenance**					
17	885 Supervision & Engineering	563,229	381,716	181,513	117,372	54.65%
18	886 Structures & Improvements	30,452	29,384	1,068	1,349	-20.83%
19	887 Mains	756,769	264,747	492,022	407,928	20.61%
20	889 Meas. & Reg. Station Exp.-General	146,442	81,486	64,956	69,265	-6.22%
21	890 Meas. & Reg. Station Exp.-Industrial	-	-	-	-	-
22	891 Meas. & Reg. Station Exp.-City Gate	8,269	1,121	7,148	2,464	190.17%
23	892 Services	317,257	71,059	246,198	264,052	-6.76%
24	893 Meters & House Regulators	535,812	127,199	408,613	253,822	60.98%
25	894 Other Equipment	11	-	11	12,275	-99.91%
26	**Total Maintenance-Distribution**	2,358,241	956,712	1,401,529	1,128,527	24.19%
27	**Total Distribution Expenses**	13,601,499	5,048,314	8,553,185	8,485,651	0.80%
28	**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**					
30	901 Supervision	-	-	-	-	-
31	902 Meter Reading	917,465	510,055	407,410	315,473	29.14%
32	903 Customer Records & Collection	2,667,644	464,337	2,203,307	2,063,174	6.79%
33	904 Uncollectible Accounts	794,459	410	794,049	757,950	4.76%
34	905 Miscellaneous Customer Accounts	44,880	43,685	1,195	988	20.95%
35	**Total Customer Accounts Expenses**	4,424,448	1,018,487	3,405,961	3,137,585	8.55%
36						
37	**Customer Service & Information Expenses**					
38	**Customer Service-Operation**					
39	907 Supervision	-	-	-	-	-
40	908 Customer Assistance	1,727,809	755,297	972,512	1,036,233	-6.15%
41	909 Inform. & Instructional Advertising	307,300	71,773	235,527	287,296	-18.02%
42	910 Misc. Customer Service & Inform.	-	-	-	21	-100.00%
43	**Total Customer Service & Information Exp.**	2,035,109	827,070	1,208,039	1,323,550	-8.73%
44						
45	**Sales Expenses**					
46	**Sales-Operation**					
47	911 Supervision	285,014	-	285,014	305,601	-6.74%
48	912 Demonstrating & Selling	-	-	-	(114)	100.00%
49	913 Advertising	47,084	9,261	37,823	3,293	>300.00%
50	916 Miscellaneous Sales	-	-	-	-	-
51	**Total Sales Expenses**	332,098	9,261	322,837	308,780	4.55%

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	920 Administrative & General Salaries	9,742,247	3,040,491	6,701,756	7,519,790	-10.88%
4	921 Office Supplies & Expenses	3,256,882	1,231,889	2,024,993	1,919,137	5.52%
5	922 Administrative Exp. Transferred-Cr.	(1,995,152)	(921,544)	(1,073,608)	(2,569,935)	58.22%
6	923 Outside Services Employed	7,114,810	4,146,124	2,968,686	1,879,190	57.98%
7	924 Property Insurance	292,327	90,777	201,550	176,381	14.27%
8	925 Legal & Claim Department	6,315,394	6,364,092	(48,698)	2,967,799	-101.64%
9	926 Employee Pensions & Benefits	3,172,804	(41,438)	3,214,242	1,923,599	67.10%
10	928 Regulatory Commission Expenses	17,189	-	17,189	25,549	-32.72%
11	930 Miscellaneous General Expenses	2,628,502	183,643	2,444,859	2,364,156	3.41%
12	931 Rents	733,071	227,546	505,525	457,069	10.60%
13	**Total Operation-Admin. & General**	31,278,074	14,321,580	16,956,494	16,662,735	1.76%
14	**Admin. & General - Maintenance**					
15	935 General Plant	933,500	(23,649)	957,149	1,148,771	-16.68%
16	**Total Admin. & General Expenses**	32,211,574	14,297,931	17,913,643	17,811,506	0.57%
17	**TOTAL OPER. & MAINT. EXPENSES**	$ 296,325,051	$ 111,545,798	$ 184,779,253	$ 169,542,014	8.99%
18						
19						
20						
21						
22						

Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$1,317,530	$1,307,924	0.73%
3	Property Taxes	17,845,330	13,029,436	36.96%
4	Crow Tribe RR and Utility Tax	50,100	42,769	17.14%
5	Blackfoot Possessoray Tax	286,420	249,241	14.92%
6	City Tax	2,801	1,115	151.21%
7	Consumer Counsel	190,134	168,271	12.99%
8	Public Service Commission	576,474	546,669	5.45%
9	Heavy Highway Use	5,084	2,530	100.95%
10	Vehicle Use Taxes	8,599	7,825	9.89%
11	Oil & Gas Royalty Taxes	170,923	131,685	29.80%
12	Equipment Taxes	-	244	-100.00%
13	Delaware Franchise Tax	43,639	22,512	93.85%
14	Excise Tax	7,687	-	-
15				
16				
17	**Canadian Taxes**			
18	Ad Valorem	15,594	7,956	96.00%
19				
20				
21				
22				
23	**TOTAL TAXES OTHER THAN INCOME**	$20,520,315	$15,518,177	32.23%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	Alliance Data System	IT Support Services	2,818,140
2	Areva T&D Inc	Energy Mgmt System Software & Maintenance	279,552
3	Asplundh Tree Experts	Tree Trimming	4,767,407
4	Automotive Rentals	Fleet Management	5,036,654
5	Bill Field Trucking	Equipment Transportation	349,899
6	Browning, Kaleczyc, Berry & Hoven	Legal Services	153,396
7	Central Air Service	Aerial Patrol Services	137,340
8	Curtis, Mallet-Prevost, Colt & Mosle LLP	Legal Services	884,589
9	Dept of Health and Human Services	USBC Services	1,168,000
10	Douma Construction	Contractor	112,612
11	Electrical Consultants Inc	Engineering Services	163,033
12	ELM Locating & Utility Services Ltd	Locating Services	1,798,545
13	Energy Share of Montana	USBC Services	431,104
14	EPC Services Company	Substation Design & Construction	2,144,917
15	Falls Construction Company	Contractor	114,401
16	First Data Integrated Systems	Customer Service	158,505
17	Graves Law Offices	Legal Services	1,065,995
18	Independent Inspection Company	Electric Line Inspection	851,655
19	Itron, Inc	Hardware/Software Maintenance	725,288
20	Kema, Inc	USB & DSM Programs & Services	2,645,745
21	Lands Energy Consultants	Consulting	148,138
22	Leonard, Street & Dienard	Legal Services	688,380
23	Mark Thompson	Consultant	109,000
24	Mercer Human Resources	Actuarial & Consulting Services	156,391
25	Nat'l Center for Appropriate Technology	Lab Testing	456,091
26	Northwest Energy Efficiency	Energy Services	357,593
27	Onyx Environmental Services LLC	Environmental Disposal Services	117,430
28	PAR Electric Contractors	Contractor	3,165,406
29	Phoenix Group	Contractor	132,618
30	Power Resource Managers	Power Scheduling & Dispatch	260,000
31	Precision Consulting	Software Security Maintenance	102,654
32	Pro Pipe Services Inc	Welding Contractor	123,485
33	Rod Tabbert Construction	Contractor	349,559
34	Spherion Corporation	Temporary Employment Services	141,707
35	State Line Contractors	Contractor	191,547
36	Strategic Energy Concepts LLC	Energy Supply Consulting Services	173,930
37	Tony Laslovich Construction	Contractor	179,396
38	Trademark Electric Inc	Contractor	510,034
39	Tri-State Drilling Inc	Drilling Services	139,296
40	Utilities Underground Location Center	Locating Services & Excavating Notifications	127,488
41	Varsity Contractors	Janitorial Services	216,342
42	Washington Forestry	Forestry Consultants	124,598
43	Zacha Underground Construction Company	Contractor	142,244
44			
45			
46			
47			
48			
49			
50	**Total of Payments Set Forth Above**		33,920,104
51			
52	1/ Due to the multiple % allocations, it is not practical to separately identify amounts charged to the electric or gas utility.		
53	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, postage and meeting expenses are paid by the company. These costs are charged to shareholder expense.

Pension Costs 1/

1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? See Schedule 14a		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: 401(a)		
4	Annual Contribution by Employer: $31,162,938	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 319,159,467	$ 300,852,204	-5.74%
8	Service cost	7,543,277	6,630,314	-12.10%
9	Interest cost	17,314,853	17,024,915	-1.67%
10	Plan participants' contributions			
11	Amendments	2,661,045		-100.00%
12	Actuarial loss	1,950,485	9,860,302	405.53%
13	Acquisition			
14	Benefits paid	(15,333,028)	(15,208,268)	0.81%
15	Benefit obligation at end of year	$ 333,296,099	$ 319,159,467	-4.24%
16	**Change in Plan Assets**	-	-	
17	Fair value of plan assets at beginning of year	$ 202,894,634	$ 188,693,229	-7.00%
18	Actual return on plan assets	11,969,529	19,409,673	62.16%
19	Acquisition			
20	Employer contribution	31,162,938	10,000,000	-67.91%
21	Plan participants' contributions	-	-	
22	Benefits paid	(15,333,028)	(15,208,268)	0.81%
23	Fair value of plan assets at end of year	$ 230,694,073	$ 202,894,634	-12.05%
24	**Funded Status**	$ (102,602,026)	$ (116,264,833)	-13.32%
25	Unrecognized net actuarial loss	(2,158,834)	(9,143,611)	-323.54%
26	Unrecognized prior service cost	2,661,045		-100.00%
27	Prepaid (accrued) benefit cost	$ (102,099,815)	$ (125,408,444)	-22.83%
28	**Weighted-average Assumptions as of Year End**	-	-	
29	Discount rate	5.50%	5.50%	
30	Expected return on plan assets	8.50%	8.50%	
31	Rate of compensation increase	3.30% Union & 3.37% Non-Union	3.30% Union & 3.37% Non-Union	
32	**Components of Net Periodic Benefit Costs**			
33	Service cost	$ 7,543,277	$ 6,630,314	-12.10%
34	Interest cost	17,314,853	17,024,915	-1.67%
35	Expected return on plan assets	(17,003,988)	(15,693,849)	7.70%
36	Amortization of prior service cost			
37	Recognized net actuarial loss		685,737	100.00%
38	Net periodic benefit cost (SEC Basis)	$ 7,854,142	$ 8,647,117	10.10%
39	**Montana Intrastate Costs:** 2/	-	-	
40	Pension Costs	$ 7,854,142	$ 12,784,268	62.77%
41	Pension Costs Capitalized	1,462,628	2,041,861	39.60%
42	Accumulated Pension Asset (Liability) at Year End	$ (102,099,815)	$ (125,408,444)	-22.83%
43	**Number of Company Employees:**			
44	Covered by the Plan	3,159	3,145	-66.98%
45	Not Covered by the Plan			
46	Active	1,052	1,043	-15.11%
47	Retired	1,214	1,209	-0.41%
48	Deferred Vested Terminated	893	893	
49	1/ NorthWestern Corporation has additional pension obligations outstanding totaling $14,983,255 and $14,688,179 for its South Dakota and Nebraska operations outstanding at December 31, 2005 and 2004, respectively, which are not reflected in the pension obligations noted above.			
50	2/For MPSC rate setting, there is a deferral between FAS 87 and expense recognized for rate making and the difference is carried in a regulatory asset in accordance with the 1988 MPSC rate order 5360d.			

Pension Costs

1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: $3,423,486	Is the Plan Over Funded? N/A		
5				

	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest cost			
10	Plan participants' contributions	Not Applicable		
11	Amendments			
12	Actuarial loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year	$ -	$ -	
16	**Change in Plan Assets**		-	
17	Fair value of plan assets at beginning of year			
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution	3,423,486	3,263,433	-4.68%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year	$ 169,953,861	$ 154,802,831	-8.91%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28		-	-	
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41		-	-	
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	Pension Costs	$ 2,693,943	$ 2,651,289	-1.58%
44	Pension Costs Capitalized	501,676	423,455	-15.59%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**			
47	Covered by the Plan - Eligible	1,332	1,317	-1.13%
48	Not Covered by the Plan			
49	Active - Participating	1,243	1,216	-2.17%
50	Retired			
51	Vested Former Employees, Retirees and Active-	312	363	16.35%
52	Noncontributing			
53				

Other Post Employment Benefits (OPEBS)

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: 93.6.24			
4	Order number: 5709d			
5	Amount recovered through rates	$4,871,039	$4,988,416	2.41%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	5.50%	5.50%	
8	Expected return on plan assets	8.50%	8.50%	
9	Medical Cost Inflation Rate 3/	10.0%,5.0%:10	11.0%,5.0%:9	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	3.30% Union & 3.37% Non-Union	3.30% Union & 3.37% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	**Describe any Changes to the Benefit Plan:**			
16				
17	**TOTAL COMPANY**	4/	4/	
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year			
20	Service cost			
21	Interest Cost			
22	Plan participants' contributions			
23	Amendments			
24	Actuarial Loss/(Gain)			
25	Acquisition			
26	Benefits paid			
27	Benefit obligation at end of year			
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year			
30	Actual return on plan assets			
31	Acquisition			
32	Employer contribution			
33	Plan participants' contributions			
34	Benefits paid			
35	Fair value of plan assets at end of year			
36	**Funded Status**			
37	Unrecognized net actuarial loss			
38	Unrecognized prior service cost			
39	Prepaid (accrued) benefit cost			
40	**Components of Net Periodic Benefit Costs**			
41	Service cost			
42	Interest cost			
43	Expected return on plan assets			
44	Amortization of prior service cost			
45	Recognized net actuarial loss			
46	Net periodic benefit cost			
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA			
49	Amount Funded through 401(h)			
50	Amount Funded through Other ________________			
51	TOTAL			
52	Amount that was tax deductible - VEBA			
53	Amount that was tax deductible - 401(h)			
54	Amount that was tax deductible - Other ____________			
55	TOTAL			
56	1/ Obtained from NorthWestern Energy-Montana's 2004 FASB 106 Valuation. Assumptions and data are as of December 31, 2004.			
57	2/ Obtained from NorthWestern Energy-Montana's 2005 FASB 106 Valuation. Assumptions and data are as of December 31, 2005.			
58	3/ First Year, Ultimate, Years to Reach Ultimate.			
59	4/ There is approximately an additional $10,544,669 and $9,021,207 in other company OPEBS liabilities outstanding at December 31, 2005 and 2004, respectively for NorthWestern Corporation's Family Protector Plan and the NorthWestern Energy's Top Hat Contracts besides what is reflected for Montana below.			

Other Post Employment Benefits (OPEBS) Continued

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active			
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$43,457,500	$46,434,906	6.85%
10	Service cost	688,022	822,705	19.58%
11	Interest Cost	2,406,644	2,428,920	0.93%
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Loss/(Gain)	1,823,327	(2,312,559)	-226.83%
15	Acquisition			
16	Benefits paid	(3,098,475)	(3,916,472)	-26.40%
17	Benefit obligation at end of year	$45,277,018	$43,457,500	-4.02%
18	**Change in Plan Assets**	-	-	
19	Fair value of plan assets at beginning of year	$8,333,378	$5,433,986	-34.79%
20	Actual return on plan assets	636,877	575,601	-9.62%
21	Acquisition			
22	Employer contribution	4,490,757	6,240,263	38.96%
23	Plan participants' contributions	-	-	
24	Benefits paid	(3,098,475)	(3,916,472)	-26.40%
25	Fair value of plan assets at end of year	$10,362,537	$8,333,378	-19.58%
26	**Funded Status**	($34,914,481)	($35,124,122)	-0.60%
27	Unrecognized net transition (asset)/obligation	$5,565,513	$6,354,473	14.18%
28	Unrecognized net actuarial loss/(gain)	24,926,576	22,462,187	-9.89%
29	Unrecognized prior service cost	152,036	180,247	18.56%
30	Prepaid (accrued) benefit cost	($4,270,356)	($6,127,215)	-43.48%
31	**Components of Net Periodic Benefit Costs**	-	-	
32	Service cost	$688,022	$822,705	19.58%
33	Interest cost	2,406,644	2,428,920	0.93%
34	Expected return on plan assets	(561,835)	(369,209)	34.29%
35	Amortization of transitional (asset)/obligation	788,960	788,960	
36	Amortization of prior service cost	28,211	28,211	
37	Recognized net actuarial loss	1,521,037	1,288,829	-100%
38	Net periodic benefit cost	$4,871,039	$4,988,416	2.41%
39	**Accumulated Post Retirement Benefit Obligation**	-	-	
40	Amount Funded through VEBA 5/ & 6/	$1,954,191	$1,392,282	-28.75%
41	Amount Funded through 401(h) 5/ & 6/	-	-	
42	Amount Funded through other - Company funds	2,916,848	3,596,134	23.29%
43	TOTAL	$4,871,039	$4,988,416	2.41%
44	Amount that was tax deductible - VEBA	$1,954,191	$1,392,282	-28.75%
45	Amount that was tax deductible - 401(h)	-	-	
46	Amount that was tax deductible - Other	2,916,848	3,596,134	23.29%
47	TOTAL	$4,871,039	$4,988,416	2.41%
48	**Montana Intrastate Costs:**			
49	Pension Costs	$4,871,039	$4,988,416	5.75%
50	Pension Costs Capitalized	907,103	796,733	-12.17%
51	Accumulated Pension Asset (Liability) at Year End	($4,270,356)	($6,127,215)	-43.48%
52	**Number of Montana Employees:**			
53	Covered by the Plan	2,156	2,140	-0.74%
54	Not Covered by the Plan	159	121	-23.90%
55	Active	1,061	1,043	-1.70%
56	Retired	968	977	0.93%
57	Spouses/Dependants covered by the Plan	127	120	-5.51%
58	5/ 2005 Trust funding was made on January 31, 2006 in the amounts of:			
59	$0 for 401(h) and $1,954,191 for VEBA. Due to 401(h) deductibility limits, the company was unable to directly fund the 401(h) Trust. All post-retirement benefits for FAS 106 obligation were paid out of company funds during 2004 and 2005.			
60	6/ 2004 Trust funding was made on January 31, 2005 in the amounts of:			
61	$0 for 401(h) and $1,392,282 for VEBA. Due to 401(h) deductibility limits, the company was unable to directly fund the 401(h) Trust.			

Note: This schedule includes the ten most highly compensated employees 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 3/	% Increase Total Compensation
1	Roger P Schrum Former Vice President, HR & Communications	141,346	46,666 A	12,089 C 20,012 D 95,556 E	315,669	511,045	-38%
2	Curtis T Pohl Vice President, Retail Operations	185,000	110,253 A	5,550 B 19,368 D 5,270 F 400 G	325,840	342,582	-5%
3	Bart A Thielbar Vice President, Information Technology	185,000	92,293 A	5,550 B 23,067 D 6,857 F 454 H	313,221	344,220	-9%
4	Michael J Young Senior Corporate Counsel	190,000	57,000 A	2,850 B 23,710 D 418 H	273,978	307,015	-11%
5	Kendall Kliewer Controller	170,952	92,582 A	20,335 D 400 G	284,269	239,894	18%
6	David G Gates Vice President, Wholesale Operations	157,212	85,015 A	19,850 D 6,500 F 500 G	269,077	256,872	5%
7	Michael L Nieman Officer, Internal Audit & Controls	145,058	92,672 A	22,225 D 500 G	260,455	203,139	28%
8	Paul James Evans Treasurer	170,952	70,320 A	18,242 D	259,514	114,079	127%
9	Bobbi L Schroeppel Vice President, Customer Care & Communications	151,971	75,984 A	19,076 D 8,742 F 600 G	256,373	243,586	5%
10	Christian P Fonss Director, Tax	159,772	67,606 A	2,363 B 15,104 D	244,844	246,119	-1%

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 3/	% Increase Total Compensation

1/ Bonuses include the following:

A> Incentive Payments earned in 2005 and paid in 2006 under the 2005 Incentive Compensation Plan as well as bonuses paid in 2005 in accordance with the court-approved Incentive Compensation and Severance Plan.

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

B> Merit Cash

C> Vacation Sellbacks / Vacation Payout

D> Employer Contributions to Benefits-Medical, Dental, Vision, Employee Assistance Program, Group Term Life, 401(k) Match

E> Severance Payment

F> Vehicle Payment / Car Allowance

G> Imputed Income

H> CB Serp Bankruptcy Settlement, including associated dividends and interest

3/ Total Compensation Reported Last Year includes value of restricted stock granted on November 1, 2004, after emergence from bankruptcy. Amounts were excluded in error from 2004 Schedule 16. Individual values on the date of grant for the 2004 restricted stock grant are as follows:

Roger P. Schrum	$216,000
Michael J. Young	$38,000
Bart A. Thielbar	$88,800
Curtis T. Pohl	$88,800
Kendall Kliewer	$32,000
David G. Gates	$71,000
Christian P. Fonss	$31,400
Michael L. Nieman	$25,000
Bobbi L. Schroeppel	$69,000
Paul James Evans	$20,000

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 3/	% Increase Total Compensation
1	Gary G. Drook Consultant Former President and Chief Executive Officer	260,769	282,500	A	15,564 B 1,165,222 C 4,893 D 1,213 E 17,375 H	1,747,536	3,287,388	-47%
2	Michael J. Hanson President & Chief Executive Officer	350,000	258,241	A	22,558 B 15,916 D 329,714 G	976,430	1,329,273	-27%
3	Brian B. Bird Vice President, Chief Financial Officer	275,000	84,541	A	22,921 B 8,203 D 80,021 E 500 F	471,185	1,096,881	-57%
4	Thomas J. Knapp Vice President, General Counsel & Corporate Secretary	250,000	134,765	A	25,332 B 9,000 D 25,000 F	444,097	419,564	6%
5	Gregory G. Trandem Vice President, Administrative Services	189,000	111,056	A	21,981 B 1,017 D 500 F 205,807 G	529,362	337,733	57%

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 3/	% Increase Total Compensation

1/ Bonuses include the following:

A> Incentive Payments earned in 2005 and paid in 2006 under the 2005 Incentive Compensation Plan as well as bonuses paid in 2005 in accordance with the court-approved Incentive Compensation and Severance Plan.

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

B> Employer Contributions to Benefits-Medical, Dental, Vision, Employee Assistance Program, Group Term Life, 401(k) Match

C> Severance Payment

D> Vehicle Payment / Car Allowance

E> Payment for Relocation Expenses & Misc Moving Gross Up

F> Imputed Income

G> CB Serp Bankruptcy Settlement, including associated dividends and interest

H> Personal Airplane Use and Gross Up

3/ Total Compensation Reported Last Year includes value of restricted stock granted on November 1, 2004, after emergence from bankruptcy. Amounts were excluded in error from 2004 Schedule 17. Individual values on the date of grant for the 2004 restricted stock grant are as follows:

Gary G. Drook	$2,059,200
Michael J. Hansen	$714,400
Brian B. Bird	$428,800
Thomas J. Knapp	$106,000
Gregory G. Trandem	$87,400

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	$2,334,527,630	$2,276,328,081	2.56%
5	105 Plant Held for Future Use	4,900	4,900	0.00%
6	107 Construction Work in Progress	30,101,840	13,779,680	118.45%
7	108 Accumulated Depreciation Reserve	(1,128,254,307)	(1,078,749,693)	4.59%
8	111 Accumulated Amortization & Depletion Reserves	(28,941,272)	(25,676,187)	12.72%
9	114 Electric Plant Acquisition Adjustments	378,735,895	378,735,895	0.00%
10	115 Accumulated Amortization-Electric Plant Acq. Adj.	(2,726,628)	(2,631,714)	3.61%
11	116 Utility Plant Adjustment - Goodwill	59,445,977	59,445,977	0.00%
12	117 Gas Stored Underground-Noncurrent	31,274,590	32,146,287	-2.71%
13	**Total Utility Plant**	1,674,168,625	1,653,383,226	1.26%
14	**Other Property and Investments**			
15	121 Nonutility Property	8,514,936	11,198,240	-23.96%
16	122 Accumulated Depr. & Amort.-Nonutililty Property	(4,417,187)	(6,085,819)	-27.42%
17	123.1 Investments in Assoc Companies and Subsidiaries	(53,299,065)	(91,950,151)	-42.03%
18	124 Other Investments	1,845,926	6,195,600	-70.21%
19	128 Miscellaneous Special Funds	-	830,917	-100.00%
20	LT Portion of Derivative Assets - Hedges	8,741,253	-	-
21	**Total Other Property & Investments**	(38,614,137)	(79,811,213)	-40.67%
22	**Current and Accrued Assets**			
23	131 Cash	291,122	16,109,543	-98.19%
24	134 Other Special Deposits	2,830,895	1,946,151	45.46%
25	135 Working Funds	43,160	40,380	6.88%
26	136 Temporary Cash Investments	-	-	-
27	141 Notes Receivable	52,535	43,763	20.05%
28	142 Customer Accounts Receivable	70,630,276	63,230,761	11.70%
29	143 Other Accounts Receivable	13,448,598	9,655,448	39.29%
30	144 Accumulated Provision for Uncollectible Accounts	(2,162,014)	(2,093,048)	3.30%
31	145 Notes Receivable-Associated Companies	-	-	-
32	146 Accounts Receivable-Associated Companies	196,416,015	307,799,918	-36.19%
33	151 Fuel Stock	2,762,036	2,768,454	-0.23%
34	154 Plant Materials and Operating Supplies	14,002,088	13,037,903	7.40%
35	164 Gas Stored - Current	23,872,256	20,890,189	14.27%
36	165 Prepayments	8,908,318	31,154,708	-71.41%
37	171 Interest and Dividends Receivable	-	-	-
39	172 Rents Receivable	71,032	81,198	-12.52%
40	173 Accrued Utility Revenues	81,299,941	58,090,885	39.95%
41	174 Miscellaneous Current & Accrued Assets	90,082	1,604,764	-94.39%
42	176 LT Portion of Derivative Assets - Hedges	8,981,894	-	-
43	(less) LT Portion of Derivative Assets - Hedges	(8,741,253)	-	-
44	**Total Current & Accrued Assets**	412,796,981	524,361,017	-19.61%
45	**Deferred Debits**			
46	181 Unamortized Debt Expense	12,982,804	13,269,663	-2.16%
47	182 Regulatory Assets	185,104,656	191,936,748	-3.56%
48	183 Preliminary Survey and Investigation Charges	-	-	-
49	184 Clearing Accounts	27,888	29,084	-4.11%
50	185 Temporary Facilities	78	78	0.00%
51	186 Miscellaneous Deferred Debits	11,538,413	940,038	>300.00%
52	189 Unamortized Loss on Reacquired Debt	1,996,826	2,207,780	-9.56%
53	190 Accumulated Deferred Income Taxes	42,651,817	327,995,937	-87.00%
54	191 Unrecovered Purchased Gas Costs	19,996,548	(4,836,562)	>-300.00%
55	**Total Deferred Debits**	274,299,030	531,542,766	-48.40%
56	TOTAL ASSETS and OTHER DEBITS	$ 2,322,650,499	$ 2,629,475,796	-11.67%

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	$ 357,945	$ 355,000	0.83%
4	204	Preferred Stock Issued	-	-	-
5	207	Premium on capital stock	-	-	-
6	211	Miscellaneous Paid-In Capital	720,856,857	715,900,934	0.69%
7	213	Discount on Capital Stock	-	-	-
8	214	Capital Stock Expense	-	-	-
9	215	Appropriated Retained Earnings	-	-	-
10	216	Unappropriated Retained Earnings	16,888,884	(6,943,543)	>-300.00%
12	217	Reacquired capital stock	(5,572,604)	-	-
13	219	Accumulated Other Comprehensive Income	4,963,949	23,006	>300.00%
14	**Total Proprietary Capital**		737,495,031	709,335,397	3.97%
15		**Long Term Debt**			
16	221	Bonds	621,920,000	687,306,000	-9.51%
17	223	Advances in Associated Companies	-	-	-
18	224	Other Long Term Debt	81,000,000	100,000,000	-19.00%
19	226	Unamortized Discount on Long Term Debt-Debit	(1,897,954)	(2,168,257)	-12.47%
20	**Total Long Term Debt**		701,022,046	785,137,743	-10.71%
21		**Other Noncurrent Liabilities**			
22	227	Obligations Under Capital Leases-Noncurrent	1,001,105	5,048,631	-80.17%
23	228.1	Accumulated Provision for Property Insurance	(370,841)	227,831	-262.77%
24	228.2	Accumulated Provision for Injuries and Damages	10,355,495	15,310,625	-32.36%
25	228.3	Accumulated Provision for Pensions and Benefits	51,583,876	56,587,632	-8.84%
26	228.4	Accumulated Miscellaneous Operating Provisions	173,666,501	177,297,557	-2.05%
27	230	Asset Retirement Obligations	3,233,138		-
28	**Total Other Noncurrent Liabilities**		239,469,274	254,472,276	-7.17%
29		**Current and Accrued Liabilities**			
30	231	Notes Payable	11,591,564	9,116,350	27.15%
31	232	Accounts Payable	110,736,781	87,597,919	26.41%
32	233	Notes Payable to Associated Companies	-	-	-
33	234	Accounts Payable to Associated Companies	4,321,765	13,849,592	-68.80%
34	235	Customer Deposits	7,429,497	7,252,925	2.43%
35	236	Taxes Accrued	131,908,694	129,230,181	2.07%
36	237	Interest Accrued	6,932,860	8,879,509	-21.92%
38	238	Dividends Declared	-	-	-
39	241	Tax Collections Payable	1,745,081	(87,755)	>-300.00%
40	242	Miscellaneous Current and Accrued Liabilities	26,490,334	24,579,893	7.77%
41	243	Obligations Under Capital Leases-Current	1,142,749	1,707,791	-33.09%
42	**Total Current and Accrued Liabilities**		302,299,325	282,126,405	7.15%
43		**Deferred Credits**			
44	252	Customer Advances for Construction	28,060,322	25,269,519	11.04%
45	253	Other Deferred Credits	126,436,775	147,144,511	-14.07%
46	254	Regulatory Liabilities	24,536,916	25,549,942	-3.96%
47	255	Accumulated Deferred Investment Tax Credits	4,564,569	5,099,450	-10.49%
48	257	Unamortized Gain on Reacquired Debt	-	-	-
49	281-283	Accumulated Deferred Income Taxes	158,766,241	395,340,553	-59.84%
50	**Total Deferred Credits**		342,364,823	598,403,975	-42.79%
51	**TOTAL LIABILITIES and OTHER CREDITS**		$ 2,322,650,499	$ 2,629,475,796	-11.79%
52					
53	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory				
54	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the				
55	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian				
56	Montana Pipeline Corp.				
57					
58					
59					
60					
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NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

We are one of the largest providers of electricity and natural gas in the Upper Midwest and Northwest, serving approximately 628,500 customers in Montana, South Dakota and Nebraska under the trade name "NorthWestern Energy." We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have distributed electricity and natural gas in Montana since 2002.

The financial statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of Federal Energy Regulatory (FERC) as set forth in its applicable Uniform System of Accounts. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates.

Between September 14, 2003 and November 1, 2004, we operated as a debtor-in-possession under the supervision of the Bankruptcy Court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*. In accordance with SOP 90-7, we applied the principles of fresh-start reporting as of the close of business on October 31, 2004. "Predecessor Company" refers to us prior to emergence from bankruptcy (operations from January 1, 2002 through October 31, 2004). "Successor Company" refers to us after emergence from bankruptcy (operations after November 1, 2004).

(2) Significant Accounting Policies

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts. This report differs from GAAP due to FERC requiring the presentation 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 (see note 4). The other significant differences consist of the following:

- Comparative statements of net income per share are not presented;
- Removal costs of transmission and distribution assets are reflected in the balance sheets as a component of accumulated depreciation of $142.6 million and $132.9 million as of December 31, 2005 and 2004, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes (see Note 6);
- Goodwill resulting from the 2002 acquisition of the Montana operations is reflected in the balance sheets as a plant acquisition adjustment of $375.8 million as of December 31, 2005 and 2004, respectively, and $59.4 million of goodwill resulting from the application of fresh-start reporting is reflected in the December 31, 2005 and 2004 balance sheets as a utility plant adjustment, both of which are reflected as goodwill for GAAP purposes (see Note 7);
- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the balance sheets as a component of accumulated depreciation of $192.8 and $193.9 million as of December 31, 2005 and 2004, respectively, in accordance with regulatory treatment as compared to plant for GAAP purposes;
- The current portion of gas stored underground is reflected in the balance sheets as current and accrued assets, as compared to materials and supplies for GAAP purposes.
- Current and long-term debt is classified in the balance sheets as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt on separate lines; and

- Accumulated deferred tax assets and liabilities are classified in the balance sheets as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred tax asset or liability.

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 South Dakota and Nebraska operations, as prescribed by the respective regulatory authorities, electric and natural gas utility revenues are based on billings rendered to customers. For our Montana operations, as prescribed by the Montana Public Service Commission (MPSC), operating revenues are recorded monthly on the basis of consumption or services rendered. Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electrical and natural gas services delivered to the customers but not yet billed at month-end.

Cash Equivalents

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

Accrued Utility Revenues

Accrued unbilled utility revenues included in customer accounts receivable totaled $81.3 million and $58.1 million at December 31, 2005 and 2004, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31, 2005	December 31, 2004
Fuel Stock	$ 2,762	$ 2,768
Materials and supplies	14,002	13,038
Gas stored underground (including the non-current portion reflected in utility plant)	55,147	53,036
	$ 71,911	$ 68,842

Regulation of Utility Operations

Our regulated operations are subject to the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulations* (SFAS No. 71). Accounting under SFAS No. 71 is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our financial statements reflect the effects of the different rate making principles followed by the jurisdiction regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are expected to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets on the balance sheet and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

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 $1.8 million and $6.2 million at December 31, 2005 and 2004, respectively.

Derivative Financial Instruments

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price of electricity and natural gas commodities as discussed further in Note 8. In order to manage these risks, we use both derivative and non-derivative contracts that may provide for settlement in cash or by delivery of a commodity, including:

- Forward contracts, which commit us to purchase or sell energy commodities in the future,
- Option contracts, which convey the right to buy or sell a commodity at a predetermined price, and
- Swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity.

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, requires that all derivatives be recognized in the balance sheet, either as assets or liabilities, at fair value, unless they meet the normal purchase and normal sales criteria. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

For contracts in which we are hedging the variability of cash flows related to forecasted transactions that qualify as cash flow hedges, the changes in the fair value of such derivative instruments are reported in other comprehensive income. The relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy and, at inception and on an ongoing basis, the effectiveness of the hedge in offsetting the changes in the cash flows of the item being hedged. Gains or losses accumulated in other comprehensive income are reclassified to earnings in the periods in which earnings are affected by the variability of the cash flows of the related hedged item. Any ineffective portion of all hedges would be recognized in current-period earnings. Cash flows related to these contracts are classified in the same category as the transaction being hedged.

We have applied the normal purchases and normal sales scope exception, as provided by SFAS No. 133 and interpreted by Derivatives Implementation Guidance Issue C15, to certain contracts involving the purchase and sale of gas and electricity at fixed prices in future periods. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. 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. Also included in plant and equipment are assets under capital lease, which are stated at the present value of minimum lease payments. Plant and equipment under capital lease were $6.0 million and $10.9 million as of December 31, 2005 and December 31, 2004, respectively.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.7% and 9.0% for Montana for 2005 and 2004, and 8.7% and 7.9% for South Dakota for 2005 and 2004, respectively. Interest capitalized totaled $1.3 million and $1.2 million for the years ended December 31, 2005 and 2004, respectively for Montana and South Dakota combined.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were $8.9 million and $3.9 million for the years ended December 31, 2005 and 2004, respectively.

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 3.4% and 3.5% for 2005 and 2004, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission three coal-fired generating plants at the end of the useful life of each plant. The annual provision for such costs is included in depreciation expense.

Stock-based Compensation

We prospectively adopted SFAS No. 123-R, *Share-Based Payment,* upon emergence from bankruptcy, with no impact to the financial statements or disclosure required as stock-based compensation consists of restricted shares of common stock. The Predecessor Company had a nonqualified stock option plan to provide for the granting of stock-based compensation to certain employees and directors, which was terminated upon our emergence from bankruptcy. The Predecessor Company accounted for this plan in accordance with the intrinsic value based method of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting. No compensation cost is recognized as the option exercise price was equal to the market price of the underlying stock on the date of grant.

If compensation costs had been recognized based on the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, there would have been no change to our net income (loss) as reported for 2004.

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.

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures, however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our statement of operations and provision for income taxes.

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 if we have prior regulatory authorization for recovery of 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, then we capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

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, then 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.

Emission Allowances

We have sulfur dioxide (SO2) emission allowances that we received with the acquisition of transmission and distribution assets in Montana. Each allowance permits a generating unit to emit one ton of SO2 during or after a specified year. We have approximately 3,200 excess SO2 emission allowances per year for years 2017 through 2031, however these allowances have no carrying value in our financial statements and the market for these years is presently illiquid. These emission allowances are not subject to regulatory jurisdiction. When excess SO2 emission allowances are sold, we reflect the gain in operating income and cash received is reflected as an investing activity.

New Accounting Standards

In March 2005, the FASB issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*, or FIN 47. FIN 47 was issued to clarify the accounting for conditional asset retirement obligations in order to have more consistent recognition of liabilities relating to asset retirement obligations and additional information on expected future cash outflows and investments in long-lived assets. FIN 47 is effective for periods ended after December 15, 2005. Based on our evaluation, we recorded a conditional asset retirement obligation of approximately $3.2 million, primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments. Recognition of this amount increased our property, plant and equipment and other noncurrent liabilities. If we had applied the provisions of FIN 47 as of December 31, 2004, we would have recorded a conditional asset retirement obligation of approximately $3.0 million.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections*. SFAS No. 154 requires retrospective application to prior periods' financial statements of a voluntary change in accounting principle and that a change in method of depreciation, amortization, or depletion for long-lived, nonfinancial assets be accounted for as a change in accounting estimate that is effected by a change in accounting principle. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. We do not believe the adoption of SFAS No. 154 will have a material impact on our results of operations or financial condition.

Reclassifications

Certain 2004 amounts have been reclassified to conform to the 2005 presentation. Such reclassifications had no impact on total proprietary capital as previously reported.

(3) Emergence from Bankruptcy and Fresh-Start Reporting

In 2002, our financial condition was significantly and negatively affected by the poor performance of our nonenergy businesses, in combination with our significant indebtedness. In early 2003, we unsuccessfully attempted to refinance, reduce and extend the maturities of our debt. 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). On October 19, 2004, the Bankruptcy Court entered an order confirming our Plan of Reorganization (Plan), which became effective on November 1, 2004.

Plan of Reorganization

The consummation of the Plan resulted in, among other things, a new capital structure, the satisfaction or disposition of various types of claims against the Predecessor Company, the assumption or rejection of certain contracts, and the establishment of a new board of directors.

In accordance with the Plan, we issued 31.1 million shares of new common stock to settle claims of debt holders. We also established a reserve of approximately 4.4 million shares of common stock upon emergence to be used to resolve various outstanding litigation matters and distributed pro rata to holders of allowed trade vendor and general unsecured claims in excess of $20,000. As of December 31, 2005, approximately 1.3 million shares have been issued from this reserve in settlement of claims. Remaining disputed unsecured claims, when allowed, will receive shares out of the reserve set aside upon emergence.

Reorganization Items

The results of operations have been impacted by Reorganization Items, including continued costs incurred related to our reorganization since we filed for protection under Chapter 11 and the impact of fresh-start reporting. The following table provides detail of the charges incurred (in thousands):

	2005	2004
Reorganization Items		
Outside services – professional fees (923)	$ 5,490	$ 39,271
Interest earned on accumulated cash (419)	—	(381)
Miscellaneous non-operating income – effects of the Plan and fresh-start reporting adjustments (421)	2,039	(571,953)
Total Reorganization Items	$ 7,529	$ (533,063)

The 2005 amount included in effects of the Plan is primarily due to a loss on the reestablishment of a liability that was removed upon emergence from bankruptcy. Included in Reorganization Items for the period ended October 31, 2004 was the Predecessor Company's gain recognized from the effects of the Plan and fresh-start reporting. The gain results from the difference between the Predecessor Company's carrying value of unsecured debt and the issuance of new common stock and the discharge of liabilities subject to compromise pursuant to the Plan. The gain from the effects of the Plan and the application of fresh-start reporting is comprised of the following (in thousands):

	Gain
Effects of the Plan and fresh-start reporting	
Issuance of new common stock and warrants	$ 713,782
Discharge of financing debt subject to compromise	(904,809)
Discharge of company obligated mandatorily redeemable preferred securities subject to compromise	(367,026)
Cancellation of indebtedness income	(558,053)
Discharge of other liabilities subject to compromise	(13,900)
Total	$(571,953)

Fresh-Start Reporting

In connection with our emergence from Chapter 11, we reflected the terms of the Plan in our December 31, 2004 financial statements, applying fresh-start reporting under SOP 90-7. Fresh-start reporting is required if (1) the reorganization value of the emerging entity's assets immediately before the date of confirmation is less than the total of all postpetition liabilities and allowed claims, and (2) holders of existing voting shares immediately before confirmation receive less than 50% of the voting shares of the emerging entity. Upon applying fresh-start reporting, a new reporting entity (the Successor Company) is deemed to be created and the recorded amounts of assets and liabilities are adjusted to reflect their estimated fair values. The reported historical financial statements of the Predecessor Company for periods ended prior to November 1, 2004 generally are not comparable to those of the Successor Company.

To facilitate the calculation of the reorganization value of the Successor Company as set forth in SOP 90-7, we developed a set of financial projections and engaged an independent financial advisor to assist in the determination. The reorganization value was determined using various valuation methods including, (i) reviewing historical financial information (ii) comparing the company and its projected performance to the market values of comparable companies, (iii) performing industry precedent transaction analysis, and (iv) considering certain economic and industry information relevant to the operating business. While the discounted cash flow approach was one of the three approaches used by the independent financial advisor to determine reorganization value, it was not the sole method used in the determination. This use of multiple approaches is consistent with methods used to determine value in most purchase business combinations. A discount rate of 7% was used in the calculation.

The independent financial advisor calculated NorthWestern's enterprise value, which represents the net equity value of NorthWestern to be distributed to creditors plus its long-term debt to be reinstated upon emergence from bankruptcy, net of cash on hand, to be within an approximate range of $1.415 billion to $1.585 billion. We selected the midpoint value of the range, $1.5 billion, as the enterprise value. This value is consistent with the Voting Creditors and Bankruptcy Court approval of our Plan. Under paragraph 09 of SOP 90-7, an entity's reorganization value "generally approximates fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring."

NorthWestern's total asset value, which is a proxy for the "reorganization value" under SOP 90-7, is approximately $2.5 billion. The projected net distributable value to NorthWestern's creditors, as calculated by an independent financial advisor, was approximately $710 million. This reflects the "reorganization value" (or total asset value) of approximately $2.5 billion, less NorthWestern's indebtedness of approximately $1.8 billion (comprised of approximately $900 million of secured reinstated debt, approximately $300 million in current liabilities and approximately $600 million in other noncurrent liabilities).

In applying fresh-start reporting, we followed these principles:

- The reorganization value was allocated to the assets in conformity with the procedures specified by Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*. The enterprise value exceeded the sum of the amounts assigned to assets and liabilities, with the excess allocated to goodwill.
- Deferred taxes were reported in conformity with applicable income tax accounting standards, principally SFAS No. 109, *Accounting for Income Taxes*. Deferred taxes assets and liabilities have been recognized for differences between the assigned values and the tax basis of the recognized assets and liabilities (see Note 13).
- Adjustment of our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognition of all previously unamortized actuarial gains and losses.
- Reversal of all items included in other comprehensive loss, including recognition of the Predecessor Company's minimum pension liability, recognition of all previously unrecognized cumulative translation adjustments and removal of a hedge gain associated with unsecured debt.
- Changes in existing accounting principles that otherwise would have been required in the financial statements of the emerging entity within the 12 months following the adoption of fresh-start reporting were adopted at the fresh-start reporting date.
- Each liability existing as of the Plan confirmation date, other than deferred taxes, was recorded at the present value of amounts to be paid determined at our computed incremental borrowing rate.

(4) Equity Investments

The following table presents our equity investments reflected in the investments in associated companies on the Balance Sheets (in thousands):

	December 31,	
	2005	2004
Clark Fork & Blackfoot, L.L.C	$ (5,752)	$ (4,963)
Natural Gas Funding Trust	999	785
NorthWestern Services Corporation	18,641	15,966
NorthWestern Investments, LLC	(69,354)	(103,738)
Risk Partners Assurance, Ltd.	2,167	—
Total Investments in Associated Companies	$ (53,299)	$ (91,950)

(5) Property, Plant and Equipment

The following table presents the major classifications of our property, plant and equipment (in thousands):

	December 31,	
	2005	2004
Land and improvements	$ 40,215	$ 37,870
Building and improvements	134,587	130,103
Storage, distribution, and transmission	1,893,516	1,846,241
Generation	136,908	130,308
Construction work in process	30,102	13,780
Other equipment	598,763	602,139
	2,834,091	2,760,441
Less accumulated depreciation	(1,159,922)	(1,107,058)
	$ 1,674,169	$1,653,383

(6) Asset Retirement Obligations

We have identified asset retirement obligations, or ARO, liabilities related to our electric and natural gas transmission and distribution assets that have been 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 have, however, previously recognized removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. These amounts do not represent Statement of Financial Accounting Standards (SFAS) No. 143 legal retirement obligations. As of December 31, 2005 and December 31, 2004, we have recognized accrued removal costs of $142.6 million and $132.9 million, respectively, which are classified as accumulated depreciation.

For our generation properties, we have accrued decommissioning costs since the generating units were first put into service in the amount of $12.8 million and $12.3 million as of December 31, 2005 and December 31, 2004, respectively, which are classified as accumulated depreciation. These amounts also do not represent SFAS No. 143 legal retirement obligations.

(7) Acquisition and Utility Plant Adjustments

We review our acquisition and utility plant adjustments for impairment annually during the fourth quarter, or more frequently if changes in circumstances or the occurrence of events suggest an impairment exists.

We retained a third party to conduct a valuation analysis in connection with our fresh-start reporting. Our consolidated enterprise value was estimated at $1.5 billion, providing for an equity value of $710 million. Upon the adoption of fresh-start reporting on October 31, 2004, we adjusted our assets and liabilities to their fair values and valued our equity to $710 million. Since we are a regulated utility, our regulated property, plant and equipment is kept at values included in allowable costs recoverable through utility rates, and the excess of reorganization value over the fair value of assets and liabilities on the date of our emergence of $435.1 million was recorded as an acquisition adjustment of $378.7 as of December 31, 2005 and 2004, respectively, with the remaining balance of $59.4 recorded as a utility plant adjustment.

(8) Risk Management and Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price of electricity and natural gas commodities. We employ established policies and procedures to manage our risk associated with these market fluctuations using various commodity and financial derivative and non-derivative instruments, including forward contracts, swaps and options.

Interest Rates

During the second quarter of 2005, we implemented a risk management strategy of utilizing interest rate swaps to manage our interest rate exposures associated with anticipated refinancing transactions of approximately $380 million. These swaps are designated as cash-flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in accumulated other comprehensive income in our Balance Sheets. We will reclassify gains and losses on the hedges from accumulated other comprehensive income into interest expense in our Statements of Income (Loss) during the periods in which the interest payments being hedged occur. At December 31, 2005, we had net unrealized pre-tax gains of $8.8 million recorded in other noncurrent assets and accumulated other comprehensive income based on the market value of our interest rate swaps. These hedging instruments are assessed on a quarterly basis in accordance with SFAS No. 133 to determine if they are effective in offsetting the interest rate risk associated with the forecasted transaction and as of December 31, 2005, we had no hedge ineffectiveness on these swaps.

Commodity Prices

During the second quarter of 2005, we implemented a risk management strategy of utilizing put options in conjunction with our forward fixed price sales to manage our commodity price risk exposure associated with our leased Colstrip 4 generation facility. These transactions are designated as cash-flow hedges of forecasted electric sales of approximately 120,000 Mwh in each of the third and fourth quarters of 2006 under the provisions of SFAS No. 133. We designated the put options as cash-flow hedges, therefore unrealized gains and losses are recorded in accumulated other comprehensive income in our Balance Sheets prior to the settlement of the anticipated hedged physical transaction. Gains or losses will be reclassified into earnings upon settlement of the underlying hedged transaction.

At December 31, 2005, we had net unrealized losses of approximately $0.9 million on these hedges recorded in accumulated other comprehensive income, and $0.2 million (including option premium) in long-term portion of derivative assets - hedges. We had no hedge ineffectiveness on these options. We expect to reclassify approximately $1.1 million of pre-tax losses on these cash flow hedges from accumulated other comprehensive income into earnings during the next twelve months based on the market prices at December 31, 2005. However, the actual amount reclassified into earnings could vary due to future changes in market prices.

(9) Related-Party Transactions

Accounts receivable from and payables to associated companies primarily include intercompany billings for direct charges, overhead, and income tax obligations. The following table reflects our accounts receivable from and accounts payable to associated companies (in thousands):

	December 31,	
	2005	2004
Accounts Receivable from Associated Companies:		
Netexit, Inc.	$ 181,796	$ 224,016
Clark Fork & Blackfoot, L.L.C.	3,827	—
Montana Megawatts I, LLC	—	77,236
Natural Gas Funding Trust	—	40
Nekota Resources, Inc.	5,443	4,458
NorthWestern Energy Marketing, LLC	2,334	2,032
NorthWestern Services Corporation	2,998	—
Risk Partners Assurance, Ltd.	18	18
	$ 196,416	$ 307,800
Accounts Payable to Associated Companies:		
Blue Dot Services, LLC	$ 1,192	$ 1,273
Clark Fork & Blackfoot, L.L.C.	—	2,457
Montana Megawatts I, LLC	2,017	—
Natural Gas Funding Trust	26	—
NorCom Advanced Technologies Inc.	85	85
NorthWestern Investments, LLC	1,002	—
NorthWestern Services Corporation	—	10,035
	$ 4,322	$ 13,850

(10) Long-Term Debt

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

	Due	Successor Company December 31, 2005	Successor Company December 31, 2004
Unsecured Debt:			
Senior Unsecured Revolver	2009	$ 81,000	$ —
Secured Debt:			
Senior Secured Term Loan B	2011	—	100,000
Mortgage bonds—			
South Dakota—7.10%	2005	—	60,000
South Dakota—7.00%	2023	55,000	55,000
Montana—7.30%	2006	150,000	150,000
Montana—8.25%	2007	365	365
Montana—7.00%	2005	—	5,386
South Dakota & Montana—5.875%	2014	225,000	225,000
Pollution control obligations—			
South Dakota—5.85%	2023	7,550	7,550
South Dakota—5.90%	2023	13,800	13,800
Montana—6.125%	2023	90,205	90,205
Montana—5.90%	2023	80,000	80,000
Discount on Notes and Bonds	—	(1,898)	(2,168)
		$ 701,022	$ 785,138

Unsecured Debt

On June 30, 2005, we entered into an amended and restated credit agreement that replaced our existing $225 million secured credit facility with an unsecured $200 million senior revolving line of credit with lower borrowing costs. The previous credit facility consisted of a $125 million five-year revolving tranche and a $100 million seven-year term tranche (senior secured term loan B.) In addition, because the amended and restated line of credit is unsecured, the $225 million of first mortgage bond collateral securing the previous facility was released by the lenders. The unsecured revolving line of credit will mature on November 1, 2009 and does not amortize. The facility bears interest at a variable rate based upon a grid which is tied to our credit rating from Fitch, Moody's, and S&P. The 'spread' or 'margin' ranges from 0.625% to 1.75% over the London Interbank Offered Rate (LIBOR). The facility currently bears interest at a rate of approximately 5.8%, which is 1.125% over LIBOR. As of December 31, 2005 we had $27.6 million in letters of credit and $81 million of borrowings outstanding under the unsecured revolving line of credit. The weighted average interest rate on the outstanding revolver borrowings was 5.2% as of December 31, 2005.

Commitment fees for the unsecured revolving line of credit were $0.1 million for the year ended December 31, 2005. Commitment fees for the revolving tranche of the old credit facility were approximately $0.2 million for the first six months of 2005, and $63,000 for the two-months ended December 31, 2004. Commitment fees for our debtor-in-possession facility were approximately $218,000 for the 10-months ended October 31, 2004, and $102,000 for the year ended December 31, 2003.

The amended and restated line of credit continues to include covenants similar to the previous credit facility, which require us to meet certain financial tests, including a minimum interest coverage ratio and a minimum debt to capitalization ratio. The amended and restated line of credit also contains covenants which, among other things, limit our ability to incur additional indebtedness, create liens, engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, make restricted payments, make loans or advances, and enter into transactions with affiliates. Many of these restrictive covenants will fall away upon the line of credit being rated "investment grade" by two of the three major credit rating agencies consisting of Fitch, Moody's and S&P. As of December 31, 2005, we are in compliance with all of the covenants under the amended and restated line of credit.

Secured Debt

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, Montana Pollution Control Obligations, and Montana Natural Gas Transition Bonds are secured by substantially all of our Montana electric and natural gas assets.

The aggregate minimum principal maturities of long-term debt, during the next five years are $156.5 million in 2006, $6.8 million in 2007, $6.1 million in 2008, $87.0 million in 2009 and $6.1 million in 2010.

(11) Comprehensive Income (Loss)

The Financial Accounting Standards Board defines comprehensive income as all changes to the equity of a business enterprise during a period, except for those resulting from transactions with owners. For example, dividend distributions are excepted. Comprehensive income consists of net income and other comprehensive income (OCI). Net income may include such items as income from continuing operations, discontinued operations, extraordinary items, and cumulative effects of changes in accounting principles. OCI may include foreign currency translations, adjustments of minimum pension liability, and unrealized gains and losses on certain investments in debt and equity securities. Due to our emergence from bankruptcy we made adjustments for fresh-start reporting in accordance with SOP 90-7 as discussed in Note 3. These adjustments resulted in removal of items recorded in accumulated OCI of $6.0 million. Comprehensive income (loss) is calculated as follows (in thousands):

	December 31, 2005	December 31, 2004
Net income (loss)	$ 59,467	$ 544,433
Other comprehensive income (loss):		
Net unrealized gain (loss) on derivative instruments qualifying as hedges, net of tax of $3,045	4,885	—
Foreign currency translation adjustment	56	23
Total other comprehensive income (loss)	4,941	23
Total comprehensive income (loss)	$ 64,408	$ 544,456

The after tax components of accumulated other comprehensive income were as follows (in thousands):

	December 31, 2005	December 31, 2004
Balance at end of period,		
Unrealized gain on derivative instruments qualifying as hedges	$ 4,885	$ —
Foreign currency translation adjustment	79	23
Accumulated other comprehensive income	$ 4,964	$ 23

(12) 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 estimates presented herein are based on pertinent information available to us as of December 31, 2005 and December 31, 2004. 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 is summarized as follows (in thousands):

	December 31, 2005		December 31, 2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Cash and working funds	$ 334	$ 334	$ 16,150	$ 16,150
Special deposits	2,831	2,831	1,946	1,946
Investments	1,846	1,846	6,196	6,196
Liabilities:				
Long-term debt (including current portion)	701,022	703,363	785,138	791,399

(13) Income Taxes

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

	December 31,	
	2005	2004
Excess tax depreciation	$ (120,652)	$(115,219)
Regulatory assets	(33,594)	(30,191)
Regulatory liabilities	(839)	169
Unbilled revenue	3,971	3,971
Unamortized investment tax credit	2,458	2,746
Compensation accruals	1,605	2,654
Reserves and accruals	31,084	49,776
Goodwill amortization	(33,395)	(24,636)
Net operating loss carryforward (NOL)	43,012	257,961
AMT credit carryforward	3,186	3,186
Deferred tax liability due to future attribute reduction	—	(207,029)
Valuation allowance	(10,461)	(10,376)
Other, net	(2,489)	(357)
	$ (116,114)	$ (67,345)

We have elected under Internal Revenue Code 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

An IRS audit of our federal income tax returns for the years 2000 through 2003 is currently in process. Management believes that the final results of these audits will not have a material adverse effect on our financial position or results of operations.

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures, however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our statement of operations and provision for income taxes.

(14) Jointly Owned Plants

We have an ownership interest in three electric generating plants, all of which are coal fired and operated by other utility companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Statements of Income (Loss). The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (S.D.)	Neal #4 (Iowa)	Coyote I (N.D.)
December 31, 2005			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$ 53,022	$ 28,870	$ 42,542
Accumulated depreciation	33,188	18,541	23,468
December 31, 2004			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$49,700	$28,106	$42,494
Accumulated depreciation	32,370	17,697	22,479

(15) Operating Leases

We lease a generation facility, vehicles, office equipment, an airplane and office and warehouse facilities under various long-term operating leases. At December 31, 2005, future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2006	$ 34,435
2007	33,838
2008	32,773
2009	32,358
2010	32,282

Lease and rental expense incurred was $31.0 million and $39.3 million for the years ended December 31, 2005 and 2004, respectively.

In January 2005, we exercised an option to extend the term of our Colstrip Unit 4 generation facility lease an additional eight years. By extending the lease term, our annual lease payment remains at $32.2 million through 2010 and decreases to $14.5 million for the remainder of the lease. Beginning in 2005 our lease expense was reduced to $22.1 million annually based on a straight-line calculation over the full term of the lease.

(16) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for employees,which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. In 2005, we applied for and received an accounting order from the MPSC to utilize a five-year average of funding cost in our costs of service, therefore we maintain a regulatory asset and amortize it based on our five-year average funding requirement in Montana. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. (See Note 18, Regulatory Assets and Liabilities, for the regulatory assets related to our pension and other postretirement benefit plans.) The prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market-related value of assets are normally amortized over the average remaining service period of active participants. However as a result of fresh-start reporting (see Note 3), we adjusted our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognizing all previously unamortized actuarial gains and losses upon emergence. The generation of any future amounts subsequent to emergence will be amortized under the same method as discussed above.

Benefit Obligations

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2005	2004	2005	2004
Reconciliation of Benefit Obligation				
Obligation at beginning of period	$373,979	$356,373	$52,391	$66,948
Service cost	8,531	7,551	688	823
Interest cost	20,174	20,300	2,853	3,325
Actuarial (gain) loss	1,236	14,045	1,705	(2,463)
Plan amendments	2,661	—	—	—
Fresh-start reporting adjustments	—	(4,727)	2,561	(11,354)
Gross benefits paid	(19,666)	(19,563)	(4,578)	(4,888)
Benefit obligation at end of period	$386,915	$373,979	$55,620	$52,391

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 $386.9 million and $271.1 million, respectively, as of December 31, 2005. 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 $384.8 million and $271.1 million, respectively, as of December 31, 2005.

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 $374.0 million and $244.6 million, respectively, as of December 31, 2004. 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 $371.8 million and $244.6 million, respectively, as of December 31, 2004.

The NorthWestern Energy pension plan was amended effective January 1, 2005 to increase the retirement death benefit from 50% to 100% of the accrued benefit. This is reflected in the plan amendment amount above, and unrecognized prior service cost below.

Balance Sheet Recognition

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

	Pension Benefits		Other Postretirement Benefits	
	December 31, 2005	December 31, 2004	December 31, 2005	December 31, 2004
Accrued benefit cost	$ (117,585)	$ (140,097)	$ (44,333)	$ (44,714)
Intangible asset	502	—	—	—
Net amount recognized	$ (117,083)	$ (140,097)	$ (44,333)	$ (44,714)

Plan Assets and Funded Status

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2005	2004	2005	2004
Reconciliation of Fair Value of Plan Assets				
Fair value of plan assets at beginning of period	$ 244,643	$ 229,771	$ 8,333	$ 5,434
Return on plan assets	14,754	24,221	637	576
Employer contributions	31,372	10,214	5,971	7,211
Gross benefits paid	(19,666)	(19,563)	(4,578)	(4,888)
Fair value of plan assets at end of period	$ 271,103	$ 244,643	$ 10,363	$ 8,333
Funded Status	$(115,812)	$(129,335)	$(45,258)	$(44,058)
Unrecognized net actuarial (gain) loss	(3,932)	(10,762)	925	(656)
Unrecognized prior service cost	2,661	—	—	—
Accrued benefit cost	$(117,083)	$(140,097)	$(44,333)	$(44,714)

Our investment goals with respect to managing the pension and other postretirement assets is to achieve and maintain a reasonably 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.

Our investment policy for fixed income investments are oriented toward risk averse, 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). 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 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, securities lending 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 current investment strategy provides for the following asset allocation policies, within an allowable range of plus or minus 5%:

	Pension Benefits	Other Benefits
Debt securities	30.0%	30.0%
Domestic equity securities	60.0	60.0
International equity securities	10.0	10.0

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, 2005 and December 31, 2004, are as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31, 2005	December 31, 2004	December 31, 2005	December 31, 2004	December 31, 2005	December 31, 2004
Cash and cash equivalents	2.0%	2.0%	1.1%	.9%	—%	—%
Debt securities	32.3	31.6	—	—	27.2	27.5
Domestic equity securities	55.2	55.8	51.5	50.4	72.3	71.9
International equity securities	10.5	10.6	9.8	9.5	0.5	0.6
Participating group annuity contracts	—	—	37.6	39.2	—	—
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

We review the asset mix on a quarterly basis. Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels.

We continually evaluate 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.

Actuarial Assumptions

The measurement dates used for the plans each year are December 31, 2005. The actuarial assumptions used to compute the net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these items generally have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

Annually, we set the discount rate based upon our review of the Citigroup Pension Index and Moody's Aa bond rate index. 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, 2003, 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 10.5%. Considering this information and future expectations for asset returns, we selected an 8.5% long-term rate of return on assets assumption for 2005 and 2004. We have reduced this assumption to 8.0% for 2006.

The health care cost trend rates are established through a review of actual recent cost trends and projected future trends. Our retiree medical trend assumptions are the best estimate of expected inflationary increases to our healthcare costs. Due to the relative size of our retiree population (under 700 members), the assumptions used are based upon both nationally expected trends and our specific expected trends. Our average increase remains consistent with the nationally expected trends.

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

	Pension Benefits Year ended December 31,		Other Post-retirement Benefits Year Ended December 31,	
	2005	2004	2005	2004
Discount rate	5.50 %	5.50%	5.50 %	5.50%
Expected rate of return on assets	8.50 %	8.50%	8.50 %	8.50%
Long-term rate of increase in compensation levels (nonunion)	3.64 %	3.37%	3.64 %	3.37%
Long-term rate of increase in compensation levels (union)	3.50 %	3.30%	3.50 %	3.30%

The postretirement benefit obligation is calculated assuming that health care costs increased by 10% in 2005 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually to 5% by the year 2010.

Net Periodic Cost

The components of the net costs for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits Year Ended December 31,		Other Post-retirement Benefits Year Ended December 31,	
	2005	2004	2005	2004
Components of Net Periodic Benefit Cost				
Service cost	$ 8,531	$ 7,551	$ 688	$823
Interest cost	20,174	20,300	2,853	3,325
Expected return on plan assets	(20,347)	(18,988)	(562)	(369)
Amortization of transitional obligation	—	129	—	—
Amortization of prior service cost	—	311	—	—
Recognized actuarial (gain) loss	—	1,068	—	467
Net Periodic Benefit Cost	$ 8,358	$ 10,371	$2,979	$4,246

Assumed health care cost trend rates have a significant effect on the amounts reported for the costs each year as well as on the accumulated postretirement benefit obligation. 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	$ 208
on postretirement benefit obligation	2,328
Effect of a one percentage point decrease in assumed health care cost trend	
on total service and interest cost components	$ (179)
on postretirement benefit obligation	(2,049)

In May 2004, the FASB issued Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*. The impact of this Medicare prescription legislation has been analyzed and determined to have minimal impact due to the limited post-age 65 liability under the post-retirement benefit plan.

Cash Flows

We anticipate making contributions of approximately $24.0 million to our pension and other postretirement benefit plans in 2006. 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.

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2006	$ 19,827	$ 4,157
2007	20,019	4,187
2008	20,422	4,098
2009	20,579	4,172
2010	21,414	4,315
2011-2015	123,321	22,440

Predecessor Company

The Predecessor Company filed several motions to terminate various nonqualified benefit plans and individual supplemental retirement contracts for former employees. All liabilities associated with these plans were removed from our balance sheet upon emergence based on our expectation that these claims would be settled through the shares from the reserve established for Class 9 claimants. Various claimants objected to the Bankruptcy Court's jurisdiction to terminate such plans and/or contracts. In July 2005, the Bankruptcy Court approved share-based settlements with most of the participants in the various nonqualified plans and supplemental retirement contracts. However, the Bankruptcy Court determined that it did not have jurisdiction to consider a motion to terminate various individual supplemental retirement contracts, therefore in 2005 we reestablished a liability of approximately $2.6 million and have resumed payments on those individual supplemental retirement contracts not covered by the Bankruptcy Court's jurisdiction.

Defined Contribution Plans

On December 31, 2004, the NorthWestern Corporation savings plan was merged into the NorthWestern Energy savings plan. These plans 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 plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Costs incurred under these plans were $3.4 million for 2005, and $3.3 million for 2004. $0.6 million for the two-month period ended December 31, 2004, $2.7 million for the 10-month period ended October 31, 2004 and $3.1 million in 2003, respectively.

(17) Director and Employee Incentive Plans

Employee Incentive Plans

In connection with the confirmation of our Plan, the Bankruptcy Court and Creditors Committee approved a New Incentive Plan to be established and administered by the new Board of Directors. The Plan reserved 2,265,957 shares of new common stock for the New Incentive Plan. Upon emergence from bankruptcy 228,315 shares of restricted stock were granted (Special Recognition Grants) under this New Incentive Plan to certain officers and key employees. The fair value at the date of issuance for these Special Recognition Grants was $4.6 million. 114,164 shares of the Special Recognition Grants vested upon emergence. The remaining shares vested on November 1, 2005 for non-officers. For officers, 10% vested on November 1, 2005, and the remaining shares vest 20% on November 1, 2006 and 20% on November 1, 2007.

In February 2005, the Board of Directors established an equity-based incentive plan, the NorthWestern Corporation 2005 Long-Term Incentive Plan (2005 LTIP), which provides for grants of stock options, share appreciation rights, restricted and unrestricted share awards, deferred share units and performance awards. The 2005 LTIP was developed in accordance with the New Incentive Plan provided for in the Plan as discussed above, and therefore did not require shareholder approval. Our directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by us, are eligible to receive grants. The purpose of the 2005 LTIP is to promote our long-term growth and profitability by providing these individuals with incentives to maximize shareholder value and otherwise contribute to our success and to enable us to attract, retain and reward the best available persons for positions of responsibility. The Human Resources Committee of our Board of Directors administers the 2005 LTIP. Under the 2005 LTIP, 700,000 shares of our common stock are available for issuance. As of December 31, 2005 there were 581,415 shares of common stock remaining available for grants under this plan.

We account for our service-based restricted stock awards using the fixed accounting method, whereby we amortize the value of the market price of the underlying stock on the date of grant to compensation expense over the service period. We reverse any expense associated with restricted stock that is canceled or forfeited during the performance or service period. Compensation expense recognized for restricted stock awards was $4.7 million for the year ended December 31, 2005, $0.2 million for the two months ended December 31, 2004, and $2.3 million for the 10-months ended October 31, 2004.

Summarized share information for our restricted stock awards, including the Special Recognition Grants and the broad-based employee and Board of Directors grant under the 2005 LTIP is as follows:

	Year Ended December 31, 2005	November 1 - December 31, 2004
Beginning unvested grants	114,151	114,151
Granted	97,651	—
Vested	175,558	—
Canceled	1,080	—
Remaining unvested grants	35,164	114,151
Weighted average fair value restricted stock granted	$31.02	$20.00

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. A DSU entitles the grantee to receive one share of common stock for each DSU at the end of the deferral period. The value of these DSUs are marked-to-market on a quarterly basis with an adjustment to directors compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number years (not to exceed 10 years). During 2005, DSUs issued to members of our Board of Directors totaled 20,934. Total compensation expense attributable to the DSUs during 2005 was approximately $0.7 million.

Predecessor Company Stock Option and Incentive Plan

All common stock options under the NorthWestern Stock Option and Incentive Plan (Option Plan) were cancelled upon emergence from bankruptcy. Under the Option Plan, the Predecessor Company had reserved 3,424,595 shares for issuance to officers, key employees and directors as either incentive-based options or nonqualified options.

Information regarding the Predecessor Company's options granted and outstanding is summarized below:

	Shares	Option Price Per Share	Weighted Average Option Price
Balance December 31, 2002	1,538,165	15.26-26.13	22.49
Issued	500,623	2.05-4.90	3.97
Canceled	(679,600)	20.30-26.13	22.23
Balance December 31, 2003	1,359,188		15.81
Application of fresh-start reporting (Note 3)	(1,359,188)		
Balance October 31, 2004 (Successor Company)	—		

The Predecessor Company had also issued 283,333 shares of common stock in 2003 under a restricted stock plan with a fair value at date of issuance of $1.2 million. These shares were also cancelled upon emergence. Compensation expense recognized was $0.4 million for the 10-months ended October 31, 2004 and $0.3 million for the year ended December 31, 2003.

(18) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 2 to the Financial Statements. Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to the customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. 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. Of these regulatory assets and liabilities, energy supply costs are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods. Because these costs are recovered as paid, they do not earn a return. We have specific orders to cover approximately 89% of our regulatory assets and approximately 96% of our regulatory liabilities.

	Note Ref.	Remaining Amortization Period	December 31, 2005	December 31, 2004
Pension	16	Undetermined	$ 123,326	$ 135,358
SFAS No. 106	16	Undetermined	33,096	35,567
Income taxes	13	Plant Lives	9,184	7,642
State & local taxes & fees		1 Year	5,697	—
Other		Various	13,802	13,370
Total regulatory assets			$ 185,105	$ 191,937
Gas storage sales		34 Years	$ 14,195	$ 6,676
Supply costs		1 Year	7,981	16,621
Other		Various	2,361	2,253
Total regulatory liabilities			$ 24,537	$ 25,550

Pension and SFAS No. 106

Through fresh-start reporting in 2004 we adjusted our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognition of all previously unamortized actuarial gains and losses. See Note 3 for further information regarding the impacts of fresh-start reporting. A pension regulatory asset has been recognized for the obligation that will be included in future cost of service. Historically, the MPSC rates have allowed recovery of pension costs on a cash basis. In 2005, the MPSC authorized the recognition of pension costs based on an average of the funding to be made over a 5-year period for the calendar years 2005 through 2009. The SDPUC allows recovery of pension costs on an accrual basis. A regulatory asset has been recognized for the SFAS No. 106 fair value adjustments resulting from fresh-start reporting. The MPSC allows recovery of SFAS No. 106 costs on an accrual basis.

Income Taxes

Tax assets 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.

State & Local Taxes & Fees

Under Montana law, utilities are allowed to reflect changes in state and local taxes and fees, and to track these changes such that the actual level of taxes and fees are recovered. In 2005, the MPSC authorized recovery of approximately 60% of the estimated increase in our local taxes and fees (primarily property taxes) in 2005 as compared to the amount of these taxes from our last general rate case in 1999. On December 2, 2005, we filed with the MPSC for an automatic rate adjustment, which reflected 100% of the under recovery of 2005 actual state and local taxes and fees and estimated state and local taxes and fees for 2006. In February 2006, the MPSC issued an order allowing recovery of approximately 60% of the 2005 actual increase and approximately 25% of the 2006 estimated increase. While we have recorded a regulatory asset consistent with the MPSC's authorization, we are disputing the reduction by the MPSC and have filed a Petition for Judicial Review in Montana District Court regarding the 2005 order. We anticipate resolving this issue in 2006, however we cannot currently predict an outcome.

Gas Storage Sales

A gas storage sales regulatory liability (cushion gas) was established in 2000 and 2001 based on gains on natural gas sales in Montana. 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. This regulatory liability is a reduction of rate base.

(19) 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 guidelines, requirements and procedures that guide default supply power procurement and their cost recovery. Compliance with these procurement procedures should mitigate the risk of nonrecovery of our costs of acquiring electric supply.

On January 23, 2003, we filed our first biennial Electric Default Supply Resource Procurement Plan with the MPSC, which fulfills the requirements established by law and describes the planning we are doing on behalf of our electric default supply customers to provide adequate, reliable and efficient annual and long-term electricity supply services at the lowest long-term cost. We have a substantial portion of the portfolio covered by the existing PPL Montana base-load contracts and the QF contracts. In December 2005, we filed our second biennial Electric Default Supply Resource Procurement Plan. This Plan focuses on the resource options and strategies to replace approximately 55 percent of the supply contracts that are expiring on June 30, 2007.

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 MPSC, the SDPUC, and the Nebraska Public Service Commission (NPSC) regulate our transmission and distribution services and approve the rates that we charge for these services, while the FERC regulates our transmission services. There have been no significant regulatory issues in South Dakota or Nebraska during the past three years. Current regulatory issues are discussed below.

A bankruptcy stipulation and agreement between the MPSC, MCC and us requires us to file a Montana electric and natural gas informational rate filing by September 30, 2006.

Electric Rates

On September 30, 2005, we filed our annual electric supply cost tracker request with the MPSC for the 12-month period ended June 30, 2005, and for projected costs for the 12-month period ended June 30, 2006. On October 14, 2005, an interim order was approved by the MPSC for the projected electric supply cost.

On June 1, 2004, we filed our annual electric supply cost tracker request with the MPSC for any unrecovered actual electric supply costs for the 24-month period ended June 30, 2004, and for projected costs for the 12-month period ended June 30, 2005. On December 16, 2005 a final order was issued by the MPSC for the 24-month electric supply costs ending June 30, 2004.

Natural Gas Rates

On August 23, 2005, we filed an annual gas cost tracker request with the MPSC for any unrecovered actual gas costs for the 12-month period ended June 30, 2005, and for the projected gas costs for the 12-month period ending June 30, 2006. On September 2, 2005, the MPSC issued an interim order, approving recovery of our projected gas costs.

Rates for our Montana natural gas supply are set by the MPSC. Each year we submit a natural gas tracker filing for recovery of natural gas costs. The MPSC reviews such filings and makes a determination as to whether or not our natural gas procurement activities were prudent. If the MPSC finds that we have not exercised prudence, then it can disallow such costs. On July 3, 2003, the MPSC issued orders disallowing the recovery of certain gas supply costs totaling $10.8 million for the July 2002 – June 2004 tracker years. The MPSC also rejected a motion for reconsideration filed by us on July 14, 2003. We filed suit in Montana District court on July 28, 2003, seeking to overturn the MSPC's decision to disallow recovery of these costs. The MPSC has approved a stipulation between us and the Montana Consumer Counsel regarding the recovery of natural gas costs for the 2003 and 2004 tracking years. With this stipulation as a foundation, we have settled with the MPSC and have been allowed recovery of previously disallowed gas costs of $4.6 million. As a result of the settlement, we recorded gas supply revenue of $4.6 million in the second quarter of 2005.

In Nebraska, where natural gas companies have been regulated by the municipalities in which they serve, the 2003 Nebraska Unicameral Legislature enacted a new law during the second quarter of 2003, shifting the regulation to the NPSC. Under the new law, the NPSC regulates rates and terms and conditions of service for natural gas companies, however, the law provides that a natural gas company and the cities in which it serves have the ability to negotiate rates for natural gas service when the natural gas company files an application for increased rates. If the cities and NorthWestern choose not to negotiate or they are unable to reach an agreement, then the NPSC will review the rate filing. Our initial tariffs, including our rates, terms and conditions for service consistent with those formerly filed with the municipalities, were filed with and accepted by the NPSC.

(20) Guarantees, Commitments and Contingencies

Qualifying Facilities Liability

In Montana we have certain contracts with Qualifying Facilities, 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 $1.6 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.3 billion through 2029. Upon adoption of fresh-start reporting, we computed the fair value of the remaining liability of approximately $367.9 million to be approximately $143.8 million based on the net present value (using a 7.75% discount factor) of the difference between our obligations under the QFs and the related amount recoverable. The following table summarizes the change in the QF liability for the year ended December 31, 2005, and two-month period ended December 31, 2004 (in thousands):

	December 31, 2005	December 31, 2004
Beginning QF liability	$ 143,381	$ 143,826
Unrecovered amount	(8,626)	(2,258)
Interest expense	10,600	1,813
Contract amendment	(4,888)	—
Ending QF liability	$ 140,467	$ 143,381

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

	Gross Obligation	Recoverable Amounts	Net
2006	$ 56,398	$ (52,061)	$ 4,337
2007	58,420	(52,567)	5,853
2008	60,574	(53,060)	7,514
2009	62,598	(53,583)	9,015
2010	64,580	(54,086)	10,494
Thereafter	1,329,039	(1,016,926)	312,113
Total	$1,631,609	$(1,282,283)	$349,326

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 30 years. Costs incurred under these contracts were approximately $433.9 million for the year ended December 31, 2005, $72.1 million for the two-months ended December 31, 2004, $259.4 million for the 10-months ended October 31, 2004 and $281.6 million for the year ended December 31, 2003. As of December 31, 2005 our commitments under these contracts are $626 million in 2006, $293 million in 2007, $194 million in 2008, $179 million in 2009, $171 million in 2010 and $395 million thereafter. These commitments are not reflected in our Financial Statements.

Environmental Liabilities

We are subject to numerous state and federal environmental laws and regulations. Because these laws and regulations are continually developing and subject to amendment, reinterpretation and varying degrees of enforcement, we may be subject to, but cannot predict with certainty, the nature and amount of future environmental liabilities. The Clean Air Act Amendments of 1990 (the Act) and subsequent amendments stipulate limitations on sulfur dioxide and nitrogen oxide emissions from coal-fired power plants. We comply with these existing emission requirements through purchase of sub-bituminous coal and we believe that we are in compliance with all presently applicable environmental protection requirements and regulations with respect to these plants. Recent legislation has been proposed, which may require further limitations on emissions of these pollutants along with limitations on carbon dioxide, particulate matter, and mercury emissions. The recent regulatory and legislative proposals are subject to normal administrative processes, however, and thus we cannot make any prediction as to whether the proposals will pass or on the impact of those actions.

The range of exposure for environmental remediation obligations at present is estimated to range between $29.5 million to $66.2 million. Our environmental reserve accrual is $44.6 million as of December 31, 2005. We anticipate that as environmental costs become fixed and determinable we will seek insurance coverage and/or rate recovery, therefore we do not expect these costs to have a material adverse effect on our consolidated financial position, ongoing operations, or cash flows.

Manufactured Gas Plants

Approximately $27.6 million of our environmental reserve accrual is related to manufactured gas plants. Two formerly operated manufactured gas plants located in Aberdeen and Mitchell, South Dakota, have been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System, or CERCLIS, list as contaminated with coal tar residue. We are currently investigating these sites pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources. At this time, we know that no material remediation is necessary at the Mitchell location. However, we anticipate that remediation will be necessary at the Aberdeen site, commencing in 2006. Our current reserve for remediation costs at the Aberdeen site is approximately $14.4 million, and we estimate that approximately $13.1 million of this amount will be incurred during the next five years. At present, we cannot estimate with a reasonable degree of certainty the timing of remediation cleanup at the other South Dakota sites.

We also own sites in North Platte, Kearney and Grand Island, Nebraska on which former manufactured gas facilities were located. In August 2002, the NDEQ conducted site-screening investigations at these sites for alleged soil and groundwater contamination. During 2004, the NDEQ conducted Phase 1 Environmental Site Assessments of the Kearney and Grand Island locations, using funding provided by the Targeted Brownfields Assessment (TBA) Program. During 2005, the NDEQ conducted Phase 2 investigations of soil and groundwater at these two locations using funding provided by the TBA Program. At present, we do not have Phase 2 investigation reports from NDEQ for either location and therefore cannot determine with a reasonable degree of certainty the timing of any remediation cleanup at our Nebraska locations.

In addition, we own sites in Butte, Missoula and Helena, Montana on which former manufactured gas plants were located. An investigation conducted at the Missoula site did not require entry into the MDEQ voluntary remediation program, but required preparation of a groundwater monitoring plan. The Butte and Helena sites, however, were placed into the MDEQ's voluntary remediation program for cleanup due to the existence of exceedences in groundwater of regulated pollutants. We conducted additional groundwater monitoring during 2005 at the Butte and Missoula sites and, at this time, we believe that natural attenuation should address the problems at these sites. Closure of the Butte and Missoula sites is expected shortly. Recent monitoring of groundwater at the Helena manufactured gas plant site suggests that groundwater remediation may be necessary to prevent certain contaminants from migrating offsite. We are currently evaluating the results of a pilot program meant to promote aerobic degradation of certain targeted contaminants. During 2006, we will complete our evaluation of the pilot program and also evaluate other alternatives including monitored natural attenuation. In light of these activities, continued monitoring of groundwater at this site is necessary for an extended time. At this time, we cannot estimate with a reasonable degree of certainty the timing of additional remediation at the Helena site.

Based upon our investigations to date, our current environmental liability reserves, applicable insurance coverage, and the potential to recoup some portion of prudently incurred remediation costs in rates, we do not expect remediation costs at these locations to be materially different from the established reserve.

Milltown Mining Waste

Our subsidiary, Clark Fork and Blackfoot, LLC (CFB), owns the Milltown Dam hydroelectric facility, a three megawatt generation facility located at the confluence of the Clark Fork and Blackfoot Rivers. In April 2003, the Environmental Protection Agency (EPA) announced its proposed remedy to address the mining waste contamination located in the Milltown Reservoir. This remedy proposed partial removal of the contaminated sediments located within the Milltown Reservoir, together with the removal of the Milltown Dam and powerhouse (this remedy was incorporated into the EPA's formal Record of Decision issued on December 20, 2004). In light of this pre-Record of Decision announcement, we commenced negotiations with the Atlantic Richfield Company, or Atlantic Richfield, to prevent a challenge from Atlantic Richfield to our statutorily exempt status under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) as a potentially responsible party. We entered into a stipulation (Stipulation) with Atlantic Richfield, the EPA, the Department of the Interior, the State of Montana and the Confederated Salish and Kootenai Tribes (collectively the Government Parties), which resolved both our liability with Atlantic Richfield in general accordance with the previously negotiated settlement agreement and established a framework to resolve our liability with the Government Parties for their claims, including natural resource restoration claims, against NorthWestern as they relate to remediation of the Milltown Site. The Stipulation caps NorthWestern's and CFB's collective liability to Atlantic Richfield and the Government Parties at $11.4 million. On June 22, 2004, the Bankruptcy Court approved the Stipulation and the funding of the Atlantic Richfield settlement, as modified by the Stipulation. The amount of the stipulated liability has been fully accrued in the accompanying financial statements. Pursuant to the Stipulation, commencing in August 2004 and each month thereafter, we pay $500,000 alternately into two escrow accounts, one for the State of Montana and one for Atlantic Richfield, until the total agreed amount is funded. As of December 31, 2005, we have fully funded the State of Montana escrow account in the amount of $2.5 million and have funded the Atlantic Richfield account in the amount of $6.0 million.

On July 18, 2005, CFB and we executed the Milltown Reservoir superfund site consent decree. After completion of the public comment period and formulation of EPA responses to the filed public concerns, the Department of Justice, on behalf of the EPA, filed a motion to enter the consent decree with the United States District Court for the District of Montana, on January 4, 2006. The consent decree was approved by the court on February 8, 2006 and becomes effective in 60 days if no appeals are filed. In light of the material environmental risks associated with the catastrophic failure of the Milltown Dam, we secured a 10-year, $100 million environmental insurance policy, effective May 31, 2002, to mitigate the risk of future environmental liabilities arising from the structural failure of the Milltown Dam caused by an act of God. We are obligated under the settlement to continue to maintain the environmental insurance policy until the Milltown Dam is removed during implementation of the remedy.

Other

We continue to manage polychlorinated biphenyl (PCB)-containing oil and equipment in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

Legal Proceedings

Magten/Law Debenture/QUIPS Litigation

On April 16, 2004, Magten Asset Management Corporation (Magten) and Law Debenture Trust Company (Law Debenture) initiated an adversary proceeding, which we refer to as the QUIPs Litigation, against NorthWestern seeking among other things, to void the transfer of certain assets and liabilities of CFB to us. In essence, Magten and Law Debenture are asserting that the transfer of the transmission and distribution assets acquired from the Montana Power Company was a fraudulent conveyance because such transfer left CFB insolvent and unable to pay certain claims. The plaintiffs also assert that they are creditors of CFB as a result of Magten owning a portion of the Series A 8.5% Quarterly Income Preferred Securities for which Law Debenture serves as the Indenture Trustee. By its adversary proceeding, the plaintiffs seek, among other things, the avoidance of the transfer of assets, declaration that the assets were fraudulently transferred and are not property of our bankruptcy estate, the imposition of constructive trusts over the transferred assets and the return of such assets to CFB. In August 2004, the Bankruptcy Court granted in part, but denied in part our motion to dismiss the QUIPs Litigation. As a result of filing the appeal of the confirmation order, the Bankruptcy Court has stayed the prosecution of this case until the appeal is finally decided. On September 22, 2005, the Delaware District Court withdrew the reference of this action to the Bankruptcy Court and will now hear this lawsuit. The parties will now prepare for trial of this lawsuit.

On April 19, 2004, Magten also filed a complaint against certain former and current officers of CFB in U.S. District Court in Montana, seeking compensatory and punitive damages for breaches of fiduciary duties by such officers. Those officers have requested CFB to indemnify them for their legal fees and costs in defending against the lawsuit and any settlement and/or judgment in such lawsuit. That lawsuit has now been transferred to the Federal District Court in Delaware. The parties will now prepare for trial of this lawsuit.

On October 19, 2004, the Bankruptcy Court entered a written order confirming our Plan. On October 25, 2004, Magten filed a notice of appeal of such order seeking, among other things, a reversal of the confirmation order. In connection with this appeal, Magten's efforts to obtain a stay of the enforcement of the confirmation order to prevent our Plan from becoming effective were denied by the Bankruptcy Court on October 25, 2004 and by the United States District Court for the District of Delaware on October 29, 2004. With no stay imposed, our Plan became effective November 1, 2004. On October 26, 2004, Magten filed a notice of appeal of the Bankruptcy Court's approval of the memorandum of understanding (MOU), which memorialized the settlement of the consolidated securities class actions and consolidated derivative litigation against NorthWestern and others. In March 2005, we moved to dismiss Magten's appeal of the confirmation order on equitable mootness grounds. Magten's appeals of the confirmation order and the order approving the MOU have been consolidated before the Delaware District Court. While we cannot currently predict the impact or resolution of Magten's appeal of the confirmation order or the MOU, we intend to vigorously defend against the appeals.

On February 9, 2005, we agreed to settlement terms with Magten and Law Debenture to release all claims, including Magten's and Law Debenture's fraudulent conveyance action pending against NorthWestern for Magten and Law Debenture receiving the distribution of new common stock and warrants from Class 8(b) in the same amounts as if they had voted to accept the Plan and a distribution from Class 9 of new common stock in the amount of approximately $17.4 million. Prior to seeking approval from the Bankruptcy Court, certain major shareholders and the Plan Committee objected to the settlement on both its economic terms and asserting that the structure of the settlement violated the Plan. After reviewing the objections and undertaking our own analysis of the potential Plan violation, we informed Magten and Law Debenture as well as the Plan Committee and the objecting major shareholders that we would not proceed with the settlement. Magten and Law Debenture filed a motion with our Bankruptcy Court seeking approval of the settlement. On March 10, 2005, the Bankruptcy Court entered an order denying the motion filed by Magten and Law Debenture. Magten and Law Debenture have appealed that order. This appeal has been docketed with the District Court, briefing has been completed, and we are awaiting a decision of the District Court. On April 15, 2005, Magten and Law Debenture filed an adversary complaint in the Bankruptcy Court against NorthWestern Corporation, Gary Drook, Michael Hanson, Brian Bird, Thomas Knapp and Roger Schrum alleging that NorthWestern and the former and current officers committed fraud by failing to include a sufficient amount of shares in the Class 9 reserve set aside for payment of unsecured claims and thus the confirmation order should be revoked and set aside. We filed a motion to dismiss or stay the litigation and on July 26, 2005, the Bankruptcy Court ordered a stay of the litigation pending resolution of the confirmation order appeal. The Federal District Court withdrew the reference, will now hear the lawsuit, and we intend to vigorously defend against the lawsuit.

Twice during 2005, Magten, Law Debenture, the Plan Committee and NorthWestern unsuccessfully engaged in mediation to resolve the pending appeals and other pending litigation described above. At this time, we cannot predict the impact or resolution of any of these lawsuits, appeals or reasonably estimate a range of possible loss, which could be material. We intend to vigorously defend against the adversary proceedings, lawsuits, appeals and any subsequently filed similar litigation. The plaintiffs' claims with respect to the QUIPs Litigation will be treated as general unsecured, or Class 9, claims and will be satisfied out of the Class 9 disputed claims reserve established under the Plan. We cannot currently predict the impact or resolution of this litigation.

McGreevey Litigation

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 U.S. District Court in Montana. The lawsuit, which was filed by 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 is named as a defendant due to the fact that we purchased The Montana Power L.L.C., which plaintiffs claim is a successor to the Montana Power Company.

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.* that temporarily stayed the litigation, as against NorthWestern, CFB, The Montana Power Company, The Montana Power L.L.C. and Jack Haffey. As a result of the confirmation of our Plan, the stay has been made permanent. On July 10, 2004, we and the other insured parties under the applicable directors and officers liability insurance policies along with the plaintiffs in the *McGreevey* case, plaintiffs in the *In Re Touch America Holdings, Inc. Securities Litigation* and the Touch America Creditors

Committee reached a tentative settlement through mediation. Among the terms of the tentative settlement, we, CFB and other parties will be released from all claims in this case, the plaintiffs in McGreevey will dismiss their claims against the third party purchasers of the generation assets and non-regulated energy assets of Montana Power Company, including PPL Montana, and a settlement fund in the amount of $67 million (all of which will be contributed by the former Montana Power Company directors and officers liability insurance carriers) will be established. The settlement is subject to the occurrence of several conditions, including approval of the proposed settlement by the Bankruptcy Court in our bankruptcy proceeding, and approval of the proposed settlement by the Federal District Court for the District of Montana, where the class actions are pending. There are various issues preventing a consensus on a global settlement and the Federal District Court has now stayed the case pending resolution of bankruptcy issues in the Touch America and NorthWestern bankruptcy cases. In the event the parties do not reach a global settlement agreement, a settlement is not approved or it does not take effect for any other reason, we intend to vigorously defend against this lawsuit. If we are unsuccessful in defending against this class action lawsuit, the plaintiffs' litigation claims are channeled to the Directors & Officers Trust established under our Plan, or alternatively would be treated as securities, or Class 14, claims and would be entitled to no recovery under our Plan. Claims by our current and former officers and directors (and the former officers and directors of The Montana Power Company) for indemnification for these proceedings would be channeled into the Directors and Officers Trust established by the Plan. The plaintiffs could elect to proceed directly against CFB and the assets owned by such entity, which are not material to our operations or financial position.

On August 9, 2005, McGreevey plaintiffs filed an action in Montana state court claiming that our transfer of certain assets to CFB was a fraudulent transfer. (The plaintiffs received approval in our bankruptcy case to initiate a similar fraudulent conveyance action as an adversary proceeding in our bankruptcy case, which they did not do. Under the terms of the settlement with the plaintiffs in the McGreevey case discussed above, they would not file such proceeding.) We have removed the action to the federal court in Montana and filed a motion to transfer the action to the Bankruptcy Court in Delaware. We also filed an adversary action in our Bankruptcy Case seeking injunctive relief against the McGreevey plaintiffs to stop them from pursuing their fraudulent conveyance action outside our bankruptcy case. McGreevey plaintiffs answered the adversary complaint and asserted counterclaims against us alleging the same fraudulent conveyance claims. McGreevey plaintiffs also filed a motion to remand the fraudulent conveyance action to state court in Montana and the same motion to certify certain issues to the Montana Supreme Court. On October 25, 2005 the Bankruptcy Court preliminarily enjoined the plaintiffs from further prosecuting their claim. The McGreevey plaintiffs have asked for leave to appeal this order and we have asked the Bankruptcy Court to deny the request. We cannot currently predict the impact or resolution of this litigation.

Other Litigation

In April 2005, a group of former employees of the Montana Power Company filed a lawsuit in the state court of Montana against us and certain officers styled *Ammondson, et al. v. NorthWestern Corporation, et al.*, Case No. DV-05-97. The former employees have alleged that by moving to terminate their supplemental retirement contracts in our bankruptcy proceeding without having listed them as claimants or giving them notice of the disclosure statement and Plan, that we breached those contracts, and breached a covenant of good faith and fair dealing under Montana law and by virtue of filing a complaint in our Bankruptcy Case against those employees from seeking to prosecute their state court action against NorthWestern, we had engaged in malicious prosecution and should be subject to punitive damages. On May 4, 2005, the Bankruptcy Court found that it did not have jurisdiction over these contracts, dismissed our action against these former employees, and transferred our motion to terminate the contracts to Montana state court where the former employees' lawsuit is pending. We unsuccessfully engaged in mediation of this dispute in November 2005. We recorded a loss of $2.6 million in the third quarter of 2005 to reestablish a liability for the present value of amounts due to these former employees under their supplemental retirement contracts and we have reestablished monthly payments to these former employees under the terms of their contracts. We intend to vigorously defend against this lawsuit, however we cannot currently predict the ultimate impact of this litigation.

In December 2003, the SEC notified NorthWestern that it had issued a formal order of private investigation and subsequently subpoenaed documents from NorthWestern, NorthWestern Communications Solutions, Expanets and Blue Dot. This development followed the SEC's requests for information made in connection with the previously disclosed SEC informal inquiry into questions regarding the restatements and other accounting and financial reporting matters. Since December 2003, we have periodically received and continue to receive subpoenas and informal requests from the SEC requesting documents and testimony from former and current employees as well as third parties regarding these matters. In January 2006, the SEC issued several Wells notices to individuals formerly associated with a now-defunct subsidiary. There have been no findings or adjudication of the underlying allegations in the Wells notices, and the SEC's investigation is ongoing and it could issue additional Wells notices. In addition, certain of our former directors and several former and current employees of NorthWestern and our subsidiary affiliates have been interviewed by representatives of the FBI and IRS concerning certain of the allegations made in the now resolved class action securities and derivative litigation as well as other matters. We have not been advised that NorthWestern is the subject of any FBI or IRS investigation. We are not aware of any other governmental inquiry or investigation related to these matters. We are fully cooperating with the SEC's investigation and intend to cooperate with the FBI and IRS if we are requested to do so in connection with any investigation. We cannot predict whether or not any other governmental inquiry or investigation will be commenced. We cannot predict when the SEC investigation will be completed or its outcome. If the SEC determines that we have violated federal securities laws and institutes civil enforcement proceedings against us, as a result of a ruling by the Bankruptcy Court, the SEC may not be able to pursue civil sanctions, including, but not limited to, monetary penalties against NorthWestern. The SEC has not appealed such order. The SEC could, however, pursue other remedies and penalties against NorthWestern.

In November 2005, we and our directors were named as defendants in a shareholder class action and derivative action entitled *City of Livonia Employee Retirement System v. Draper, et al.,* pending in the U.S. District Court for the District of South Dakota. The plaintiff claims, among other things, that the directors breached their fiduciary duties by not sufficiently negotiating with Montana Public Power Inc. and Black Hills Corporation, two entities that had made public, unsolicited offers to purchase NorthWestern. After the Board of Directors adopted our shareholders' rights plan on December 5, 2005, this plaintiff also sought a temporary restraining order and preliminary injunction to prevent the implementation of the rights plan or any other defensive measures. On December 16, 2005, the Federal District Court denied the plaintiff's application. The Federal District Court has scheduled a trial on plaintiffs' request for a permanent injunction against the rights plan and other measures, which will commence on March 21, 2006.. We intend to vigorously defend against the plainitffs' claims; however, we cannot currently predict the ultimate impact of this litigation.

In February 2006, we and our directors were named as defendants in an action entitled *Harbinger Capital Partners Master Fund I, LTD v. Hanson, et al.,* pending in the Delaware Court of Chancery for Newcastle County. The plaintiffs sought a preliminary and permanent injunction finding that the application of the beneficial ownership provisions of the shareholders' rights plan may not prevent plaintiff from seeking to build a coalition slate with other shareholders or circulate a referendum to shareholders. On February 22, 2006, the Delaware Court of Chancery denied plaintiff's request for expedited proceedings on their preliminary injunction motion, ruling that it would await rulings on the issue by the federal court in South Dakota. The court has not set a schedule in this action. We intend to vigorously defend against the plaintiff's claims; however, we cannot currently predict the ultimate outcome of this litigation.

Relative to Colstrip Unit 4's long-term coal supply contract with Western Energy Company (WECO), Mineral Management Service of the United States Department of Interior issued orders to WECO in 2002 and 2003 to pay additional royalties concerning coal sold to Colstrip Units 3 and 4. The orders assert that additional royalties are owed as a result of WECO not paying royalties under a coal transportation agreement from 1991 through 2001. WECO has appealed these orders and this matter is currently pending before the Interior Board of Land Appeals of the Department of Interior. In addition, the Montana Department of Revenue has asserted various tax and royalty demands, which are being appealed. We are monitoring the progression of these matters. WECO has asserted that any potential judgment would be considered a pass-through cost under the coal supply agreement. Based on our review, we do not believe any potential judgment would qualify as a pass-through cost under the terms of the coal supply agreement. Neither the outcome of these matters nor the associated costs can be predicted at this time.

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.

Disputed Claims Reserve

Upon consummation of our Plan, we established a reserve of approximately 4.4 million shares of common stock from the shares allocated to holders of our trade vendor claims in excess of $20,000 and holders of Class 9 unsecured claims. The shares held in this reserve may be used to resolve various outstanding unsecured claims and unliquidated litigation claims, as these claims were not resolved or deemed allowed upon consummation of our Plan. We have surrendered control over the common stock provided and the shares reserve is administered by our transfer agent; therefore we recognized the issuance of the common stock upon emergence. If excess shares remain in the reserve after satisfaction of all obligations, such amounts would be reallocated pro rata to the allowed Class 7 and 9 claimants.

(21) Capital Stock

Successor Company

The Successor Company is a Delaware corporation and filed a new certificate of incorporation (New Articles). The New Articles authorized 250,000,000 shares consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. As a result of the Predecessor Company's emergence from bankruptcy, the Successor Company issued 35,500,000 shares of common stock in settlement of claims. Pursuant to the Plan, such stock had an agreed value of $710.0 million. Accordingly, the Successor Company recorded common stock and additional paid-in capital of $355,000 and $709.6 million, respectively, in the Balance Sheet as of October 31, 2004. In addition, the Plan reserved 2,265,957 shares of new common stock for the New Incentive Plan, of which 228,315 shares were granted for Special Recognition Grants (see Note 17).

Concurrent with our emergence from bankruptcy we issued 4,620,333 warrants, each entitling the holder thereof to purchase one share of common stock, to certain holders of class 8(a) and 8(b) claims in settlement of their allowed claim. These warrants are exercisable from November 1, 2004 through November 1, 2007 at a current adjusted strike price of $27.48. We recognized $3.8 million of expense associated with these warrants as a reduction of cancellation of indebtedness income.

Repurchase of Common Stock

On November 8, 2005, our Board of Directors authorized a common stock repurchase program that allows us to repurchase up to $75 million of common stock. Purchases under the stock repurchase program may be made in the general open market in accordance with Rule 10b-18 under the Securities Exchange Act of 1934. We are also authorized to make privately negotiated repurchases in appropriate circumstances. The purchases are based on a number of factors, including price, volume and timing. From the program's inception through December 31, 2005 we have repurchased in open market transactions 96,442 shares of common stock for approximately $2.8 million.

We also retired 95,799 shares of common stock during 2005, which were tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards. These shares were retired based on their fair market value on the vesting date.

Shareholder Rights Plan

On December 5, 2005, our Board of Directors adopted a shareholder rights plan, which declared a dividend of one right (Right) for each outstanding share of our common stock at the close of business on December 15, 2005. Each Right entitles the registered holder to purchase from us a unit consisting of 1/1000 of a share (Unit) of Preferred Stock at a purchase price of $100 per Unit, subject to adjustment. The shareholder rights plan is intended to allow the Board of Directors to pursue its review of strategic alternatives in order to maximize value for all shareholders, ensure the fair treatment of all shareholders in the event of a hostile takeover attempt and to encourage a potential acquirer to negotiate with the Board of Directors a fair price for all shareholders before attempting a takeover.

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	$12,873	$12,873	0.00%
3	2302 Franchises and Consents	114,169	114,169	0.00%
4	2303 Miscellaneous Intangible Plant	479,614	507,254	-5.45%
5	**Total Intangible Plant**	606,656	634,296	-4.36%
6				
7	**Underground Storage Plant**			
8	2350 Land and Land Rights	4,197,945	4,140,119	1.40%
9	2351 Structures and Improvements	2,981,317	2,905,632	2.60%
10	2352 Wells	7,801,650	7,801,650	0.00%
11	2353 Lines	7,108,518	7,088,914	0.28%
12	2354 Compressor Station Equipment	7,306,417	7,306,416	0.00%
13	2355 Measuring & Regulating Equip.	2,059,733	1,998,228	3.08%
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**	32,510,745	32,296,124	0.66%
17				
18	**Transmission Plant**			
19	2365 Rights of Way	5,915,970	5,810,431	1.82%
20	2366 Structures and Improvements	9,127,487	8,820,235	3.48%
21	2367 Mains	142,659,565	141,414,933	0.88%
22	2368 Compressor Station Equipment	17,782,880	17,782,880	0.00%
23	2369 Meas. & Reg. Station Equipment	11,531,631	11,160,912	3.32%
24	2370 Communication Equipment	-	-	-
24	2371 Other Equipment	752,677	83,701	>300.00%
25	**Total Transmission Plant**	187,770,210	185,073,092	1.46%
26				
27	**Distribution Plant**			
28	2374 Land and Land Rights	874,556	874,556	0.00%
29	2375 Structures and Improvements	71,404	89,106	-19.87%
30	2376 Mains	84,117,419	81,912,860	2.69%
31	2377 Compressor Station Equipment	-	-	-
32	2378 M&R Station Equip.-General	2,184,975	2,055,115	6.32%
33	2379 M&R Station Equip.-City Gate	-	-	-
34	2380 Services	54,383,184	53,791,734	1.10%
35	2381 Customers Meters and Regulators	42,145,294	28,836,651	46.15%
36	2382 Meter Installations	-	11,231,162	-100.00%
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	2,903	2,903	0.00%
42	**Total Distribution Plant**	183,836,069	178,850,421	2.79%

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	0.00%
4	2390 Structures and Improvements	685,819	679,257	0.97%
5	2391 Office Furniture and Equipment	246,612	1,151,854	-78.59%
6	2392 Transportation Equipment	4,727,988	4,725,206	0.06%
7	2393 Stores Equipment	10,225	11,131	-8.14%
8	2394 Tools, Shop & Garage Equipment	2,021,116	3,934,983	-48.64%
9	2395 Laboratory Equipment	764,646	775,651	-1.42%
10	2396 Power Operated Equipment	1,563,742	1,532,195	2.06%
11	2397 Communication Equipment	1,398,572	1,353,740	3.31%
12	2398 Miscellaneous Equipment	89,431	92,775	-3.60%
13	2399 Other Tangible Property	-	-	-
14	**Total General Plant**	11,609,826	14,358,467	-19.14%
15	**Total Gas Plant in Service**	416,333,506	411,212,400	1.25%
16				
17	4101 Gas Plant Allocated from Common	28,682,658	27,975,885	2.53%
18	2105 Gas Plant Held for Future Use	4,900	4,900	0.00%
19	2107 Gas Construction Work in Progress	3,212,813	1,441,178	122.93%
20	2117 Gas in Underground Storage	51,145,112	49,555,704	3.21%
21				
22				
23	**TOTAL GAS PLANT**	$499,378,989	$490,190,067	1.87%
24				
25				
26	**CONSOLIDATED**	December 31,		
27	**PLANT IN SERVICE**	2005	2004	
28				
29	Montana Electric	$ 1,224,332,263	$ 1,188,868,415	
30	Yellowstone National Park	11,451,368	11,585,224	
31	Colstrip Unit 4	74,391,022	71,812,609	
32	Montana Natural Gas (Includes CMP)	416,333,506	411,212,400	
33	Common	86,181,588	83,550,399	
34	Townsend Propane	1,410,712	1,398,063	
35	South Dakota Electric	365,273,507	356,484,058	
36	South Dakota Natural Gas	101,740,399	98,765,468	
37	South Dakota Common	50,180,127	52,651,445	
38	Asset Retirement Obligation	3,233,138	-	
39	**TOTAL PLANT**	$ 2,334,527,630	$ 2,276,328,081	

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	32,296,124	17,096,760	16,231,901	2.68%
7					
8	Other Storage	-	-	-	-
9					
10	Transmission	184,865,905	68,952,348	65,742,756	1.77%
11					
12	Distribution	178,850,421	74,189,985	69,735,583	3.00%
13					
14	General and Intangible	14,788,508	8,073,191	9,138,449	7.12%
15					
16	Common	26,974,872	10,211,723	8,649,070	6.84%
17					
18	**TOTAL ACCUMULATED**				
19	**DEPRECIATION**	$437,775,830	$178,524,007	$169,497,759	2.57%
20					
21					
22					

	CONSOLIDATED ACCUMULATED DEPRECIATION	December 31, 2005	December 31, 2004
23	CONSOLIDATED	December 31,	
24	ACCUMULATED DEPRECIATION	2005	2004
25			
26	Montana Electric	$526,947,516	$490,761,261
27	Yellowstone National Park	6,734,257	6,393,096
28	Colstrip Unit 4	34,186,431	33,146,070
29	Montana Natural Gas (Includes CMP)	168,312,284	160,848,689
30	Common	31,417,118	26,521,872
31	Townsend Propane	399,982	354,707
32	South Dakota Electric	193,756,781	185,507,495
33	South Dakota Natural Gas	41,288,807	38,566,168
34	South Dakota Common	16,039,957	15,481,818
35	Acquisition Writedown	138,214,749	146,708,310
36	CWIP-Capital Retirement Clearing	-102,303	136,394
37	TOTAL ACCUMULATED DEPRECIATION	$1,157,195,579	$1,104,425,880

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS			
	Account Number & Title	This Year Cons. Utility	Last Year Montana	%Change
1				
2	154 Plant Materials & Operating Supplies			
3	Assigned and Allocated to:			
4	Operation & Maintenance	-	-	-
5	Construction	-	-	-
6	Storage Plant	$ 145,682	$ 127,013	14.70%
7	Transmission Plant	841,408	727,847	15.60%
8	Distribution Plant	823,779	703,374	17.12%
9				
10	**TOTAL MATERIALS & SUPPLIES**	$1,810,869	$1,558,234	16.21%
11				
12				
13	**CONSOLIDATED**	December 31,		
14	**MATERIALS & SUPPLIES**	2005	2004	
15				
16	Montana Natural Gas	$1,810,869	$1,558,234	
17	Montana Electric	7,148,928	6,868,981	
18	Colstrip Unit 4	1,436,641	1,344,767	
19	South Dakota Electric	3,605,650	3,265,921	
20				
21	**TOTAL MATERIALS & SUPPLIES**	$14,002,088	$13,037,903	

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%
	% Capital Structure	% Cost Rate	Weighted Cost
NorthWestern Corp Consolidated /2			
Common Equity	55.70%	10.75%	5.99%
Preferred Stock	0.00%	0.00%	0.00%
QUIPS Preferred	0.00%	0.00%	0.00%
Long Term Debt	44.30%	6.37%	2.82%
Other			
TOTAL	100.00%		8.81%

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

2/ Northwestern Corporations' consolidated capital structure as of 12/31/2005 was taken from the most recent 10-K.

Sch. 23

STATEMENT OF CASH FLOWS

Line	Description	This year	Last year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 59,466,590	$ 544,432,692	-89.08%
4	Noncash Charges (Credits) to Income:			
5	Depreciation	73,609,317	71,845,113	2.46%
6	Amortization, Net	(625,151)	(831,823)	24.85%
7	Other Noncash Charges to Net Income, Net	1,105,356	(580,022,276)	100.19%
8	Deferred Income Taxes, Net	45,972,349	(13,150,181)	>300.00%
9	Investment Tax Credit Adjustments, Net	(534,881)	(534,824)	-0.01%
10	Change in Operating Receivables, Net	19,613,947	12,137,275	61.60%
11	Change in Materials, Supplies & Inventories, Net	(3,939,833)	(10,752,246)	63.36%
12	Change in Operating Payables & Accrued Liabilities, Net	15,327,782	61,783,336	-75.19%
13	Allowance for Funds Used During Construction (AFUDC)	(758,738)	(454,548)	-66.92%
14	Change in Other Assets & Liabilities, Net	(74,312,175)	32,300,870	>-300.00%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(233,242)	9,855,962	-102.37%
17	Change in Regulatory Assets	6,832,092	(1,963,851)	>300.00%
18	Change in Regulatory Liabilities	(1,013,026)	8,241,842	-112.29%
19	**Net Cash Provided by/(Used in) Operating Activities**	140,510,388	132,887,341	5.74%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(79,178,268)	(79,371,496)	0.24%
22	(Net of AFUDC)			
23	Proceeds from Disposal of Noncurrent Assets	5,005,009	15,452,730	-67.61%
24	Other Investing Activities:			
25	Change in Other Special Deposits & Funds (restricted cash)	(53,827)	6,801,310	-100.79%
26	Proceeds from Sales of Investments	4,677,608	126,307	>300.00%
27	Purchase of Investment Securities	(118,800,000)	(194,875,000)	39.04%
28	Proceeds from Sales of Investment Securities	118,800,000	194,875,000	-39.04%
29	Distribution from Subsidiaries	43,219,640	10,000,000	>300.00%
30				
31	**Net Cash Provided by/(Used in) Investing Activities**	(26,329,838)	(46,991,149)	43.97%
32	**Cash Flows from Financing Activities:**			
33	Proceeds from Issuance of:			
34	Long-Term Debt	-	325,000,000	-100.00%
35	Credit Facilities Borrowings, Net	81,000,000	-	
36	Payment for Retirement of:			
37	Long-Term Debt	(165,386,000)	(400,546,000)	58.71%
38	Capital Lease Obligations, Net	(4,612,569)	(2,286,333)	-101.75%
39	Dividends on Common Stock	(35,634,163)	-	
40	Other Fianacing Activities:			
41	Exercise of Warrants	132,092	-	
42	Deferred Gas Storage Financing	2,475,214	9,116,350	-72.85%
43	Debt Financing Costs	(2,398,161)	(16,199,998)	85.20%
44	Treasury Stock Purchases	(5,572,604)	-	
45	**Net Cash Provided by (Used in) Financing Activities**	(129,996,191)	(84,915,981)	-53.09%
46	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(15,815,641)	980,211	>-300.00%
47	**Cash and Cash Equivalents at Beginning of Year**	16,149,923	15,169,713	6.46%
48	**Cash and Cash Equivalents at End of Year**	$ 334,282	$ 16,149,923	-97.93%
49		(0)	(0)	

This financial statement is 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. As such, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corp.

Sch. 24

MONTANA 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 %
1									
2	**First Mortgage Bonds**								
3	8.25% Series, Due 2007	12/05/91	02/01/07	$55,000,000	$54,550,100	$364,992	8.260%	$30,167	8.26%
4	5.875% Series, Due 2014	11/01/04	11/01/14	161,000,000	161,000,000	161,000,000	5.875%	9,934,663	6.17%
5	**Total First Mortgage Bonds**			$216,000,000	$215,550,100	$161,364,992		$9,964,830	6.18%
6									
7	**Pollution Control Bonds**								
8	6-1/8% Series, Due 2023	06/30/93	05/01/23	$90,205,000	$88,199,743	$89,039,935	6.428%	$5,608,399	6.30%
9	5.90% Series, Due 2023	12/30/93	12/01/23	80,000,000	79,040,800	79,423,001	5.841%	4,763,619	6.00%
10	**Total Pollution Control Bonds**			$170,205,000	$167,240,543	$168,462,936		$10,372,017	6.16%
11									
12	**Other Long Term Debt**								
13	Cost Associated with Prior Debt Retirements	N/A	N/A					$184,978	N/A
14	**Total Other Long Term Debt**			$0	$0	$0		$184,978	
15	**TOTAL LONG TERM DEBT**			$386,205,000	$382,790,643	$329,827,928		$20,521,825	6.22%

17 1/ Total Long-Term Debt does not include amounts due within 1 year - $150,000,000 (less a discount of $155,882) on December 1, 2006.

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	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	35,611,026	$20.15				$28.75	$27.76	
February	35,611,026	20.28				29.13	27.50	
March	35,611,026	20.23	$0.53	$0.22		28.75	25.52	
April	35,611,720	20.26				28.58	26.10	
May	35,589,490	20.38				29.58	27.44	
June	35,622,759	19.85	(0.11)	0.22		31.77	28.09	
July	35,622,759	19.94				32.15	30.75	
August	35,623,090	20.10				32.53	29.84	
September	35,689,510	20.03	0.25	0.25		31.27	29.74	
October	35,691,079	20.31				30.37	28.04	
November	35,622,279	20.42				32.43	27.82	
December	35,602,253	20.71	1.00	0.31		32.19	30.82	
TOTAL Year End	35,630,038	$20.71	$1.67	$1.00	40.12%	$31.07		18.6

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2005.

Sch. 27

MONTANA EARNED RATE OF RETURN - GAS

Line		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$440,071,113	$426,409,429	3.20%
3	108	Accumulated Depreciation	(174,551,183)	(164,027,831)	-6.42%
4					
5		**Net Plant in Service**	$265,519,930	$262,381,598	1.20%
6		Additions:			
7	154, 156	Materials & Supplies	$2,972,623	$2,776,577	7.06%
8	165	Prepayments			
9		Other Additions 1/	33,335,206	34,060,174	-2.13%
10					
11		**Total Additions**	$36,307,829	$36,836,751	-1.44%
12		Deductions:			
13	190	Accumulated Deferred Income Taxes 2/	$20,513,689	$14,777,151	38.82%
14	252	Customer Advances for Construction	4,984,210	4,654,333	7.09%
15	255	Accumulated Def. Investment Tax Credits			
16		Other Deductions	35,769,852	26,380,774	35.59%
17					
18		**Total Deductions**	$61,267,751	$45,812,258	33.74%
19		**Total Rate Base**	$240,560,008	$253,406,091	-5.07%
20		**Net Earnings**	$18,786,880	$18,642,730	0.77%
21		**Rate of Return on Average Rate Base**	7.810%	7.357%	6.15%
22		**Rate of Return on Average Equity 3/**	9.016%	6.841%	31.79%
23					
24		**Major Normalizing and**			
25		**Commission Ratemaking Adjustments**			
26		Rate Schedule Revenues	($196,077)	$1,809,739	-110.83%
27		Gas Cost Disallowance	(4,635,351)	2,822,981	-264.20%
28		Funding Trust Regulatory Liability	213,792	(117,238)	282.36%
29		Restructuring Costs	0	562,466	-100.00%
30					
31		Non-Allowables:			
32		Advertising	53,988	20,365	165.10%
33		Benefit Restoration Plan	0	53,670	-100.00%
34		Dues, Contributions, Other	22,947	19,152	19.82%
35					
36		Associated Income Taxes 4/	2,778,259	(2,643,874)	205.08%
37		**Total Adjustments**	($1,762,442)	$2,527,261	-169.74%
38		**Revised Net Earnings**	$17,024,438	$21,169,991	-19.58%
39		**Adjusted Rate of Return on Average Rate Base**	7.077%	8.354%	-15.29%
40		**Adjusted Rate of Return on Average Equity 3/**	6.815%	9.272%	-26.50%
41					

42 1/ Other additions includes a FAS 109 Regulatory Asset that provides an offset to the accumulated
43 deferred taxes.

45 2/ The Annual Report for 2004 contained an error in the Accumulated Deferred Income Taxes balance.
46 This balance has been corrected and reclassified to conform to the 2005 presentation.

48 3/ Return on Equity calculated using the capital structure approved in Docket D2000.8.113.

50 4/ Associated Income taxes include an interest synchronization adjustment based upon the approved
51 capital structure in Docket D2000.8.113.

Sch. 27 cont.

MONTANA EARNED RATE OF RETURN - GAS

Description	This Year	Last Year	% Change
Detail - Other Additions			
FAS 109 Regulatory Asset	$129,601	$173,538	-25.32%
Gas Stored Underground	32,029,594	32,170,919	-0.44%
Cost of Refinancing Debt	49,361	342,338	-85.58%
1997 and 1998 Severance Plans	0	41,884	-100.00%
1999 Severance Plan		0	-
ORCOM Development Costs		0	-
SAP Development Costs	1,126,650	1,331,495	-15.38%
Total Other Additions	$33,335,206	$34,060,174	-2.13%
Detail - Other Deductions			
Personal Injury and Property Damage	($2,400,903)	($3,381,124)	28.99%
Storage Gas Sales 2000 & 2001	14,404,979	8,640,920	66.71%
Gross Cash Requirements	5,686,833	3,194,678	78.01%
Met Life Refund		0	-
Bond Refinancing CTC - GP	4,298,064	4,298,064	0.00%
Bond Refinancing CTC - RA	13,689,232	13,689,232	0.00%
USBC Gas	91,647	(60,996)	250.25%
Total Other Deductions	$35,769,852	$26,380,774	35.59%

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)	$ 445,016,164
5	105	Plant Held for Future Use	4,900
6	107	Construction Work in Progress	3,212,813
7	117	Gas in Underground Storage	51,145,112
8	151-163	Materials & Supplies	1,810,869
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	178,524,007
11	252	Contributions in Aid of Construction	5,314,424
12	**NET BOOK COSTS**		$ 317,351,427
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	$ 245,539,799
17			
18	**Total Operating Revenues**		$ 245,539,799
19			
20	401-402	Other Operating Expenses (including regulatory amortizations)	$ 186,067,757
21	403-407	Depreciation & Amortization Expenses	12,382,240
22	408.1	Taxes Other than Income Taxes	20,520,315
23	409-411	Federal & State Income Taxes	7,782,607
24			
25	**Total Operating Expenses**		$ 226,752,919
26	**Net Operating Income**		$ 18,786,880
27			
28	415-421.1	Other Income	9,835,410
29	421.2-426.5	Other Deductions	984,635
30	**NET INCOME BEFORE INTEREST EXPENSE**		$27,637,655
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	146,261
34		Commercial	20,320
35		Industrial	335
36		Other (including interdepartmental)	143
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		167,059
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	86.0
41		Average Annual Residential Cost per (Dkt)	$10.76
42		Average Residential Monthly Bill	$77.14
43			
44		Plant in Service (Gross) per Customer	$2,664

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	461	78	2	541
2	Amsterdam		55	8		63
3	Anaconda	9,417	3,336	328	5	3,669
4	Augusta	284	188	43	1	232
5	Belfry	219	5	-	-	5
6	Belgrade	5,728	4,429	573	2	5,004
7	Big Mountain		149	32	-	181
8	Big Sandy	703	297	72	-	369
9	Big Timber	1,650	913	173	9	1,095
10	Bigfork	1,421	1,034	168	-	1,202
11	Billings	89,847	13	2	3	18
12	Bonner	1,693	78	5	-	83
13	Boulder	1,300	477	80	1	558
14	Bozeman	27,509	16,690	2,514	12	19,216
15	Browning	3,877	1,070	166	3	1,239
16	Buffalo		5	-	-	5
17	Butte	33,892	12,300	1,327	44	13,671
18	Cardwell	40	17	5	-	22
19	Carter	62	29	10	-	39
20	Chester	871	375	116	3	494
21	Chinook	1,386	719	134	6	859
22	Choteau	1,802	840	170	3	1,013
23	Churchill		394	44	-	438
24	Clancy	1,406	668	29	1	698
25	Clinton		366	16	1	383
26	Columbia Falls	3,645	3,047	325	4	3,376
27	Columbus	1,748	994	151	5	1,150
28	Conrad	2,753	1,123	197	15	1,335
29	Coram	337	114	21	-	135
30	Corvallis	443	1,012	90	1	1,103
31	Cut Bank	3,105	48	12	1	61
32	Deer Lodge	3,421	1,586	199	7	1,792
33	Dillon	3,752	1,966	329	6	2,301
34	Drummond	318	205	51	2	258
35	East Glacier Park	396	125	46	1	172
36	East Helena	1,642	1,907	106	4	2,017
37	Elliston	225	97	13	-	110
38	Essex		73	13	1	87
39	Fairfield	659	402	84	4	490
40	Florence	901	1,105	70	1	1,176
41	Floweree		44	8	-	52
42	Fort Belnap	1,262	351	55		406
43	Fort Benton	1,594	627	157	1	785
44	Fort Harrison			3	58	61
45	Fort Shaw	274	103	13	-	116
46	Galata		3	-	-	3
47	Gallatin Gateway		155	30	-	185
48	Garneill		9	1	-	10
49	Garrison	112	24	4	-	28
50	Gildford	185	82	28	-	110
51	Gransdale		22	2	-	24
52	Great Falls	56,690	949	43	4	996

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Greycliff	56	44	4	-	48
2	Hall		62	12	-	74
3	Hamilton	3,705	3,638	640	9	4,287
4	Harlem	848	328	72	2	402
5	Harlowton	1,062	532	100	2	634
6	Havre	9,621	4,499	624	9	5,132
7	Helena	45,819	15,896	2,215	43	18,154
8	Hingham	157	84	27	-	111
9	Hungry Horse	934	256	32	-	288
10	Iverness	103	36	14	-	50
11	Jefferson City	295	131	11	2	144
12	Joplin	210	96	27	-	123
13	Judith Gap	164	66	15	-	81
14	Kalispell	14,223	10,523	1,845	17	12,385
15	Kremlin	126	48	16	-	64
16	Laurel	6,255	11	-	-	11
17	Ledger		6	-	-	6
18	Lewistown	6,178	2,862	472	14	3,348
19	Livingston	7,348	3,814	527	17	4,358
20	Logan		52	4	1	57
21	Lohman		2	1	-	3
22	Lolo	3,388	1,340	87	-	1,427
23	Loma	92	39	19	-	58
24	Manhattan	1,396	691	90	1	782
25	Martin City	331	114	15	-	129
26	Milltown		74	8	-	82
27	Missoula	57,053	27,603	3,523	54	31,180
28	Montana City		640	57	-	697
29	Moore	186	3	-	-	3
30	Philipsburg	914	430	81	-	511
31	Ramsay		38	7	-	45
32	Red Lodge	2,177	1,632	261	7	1,900
33	Reedpoint	185	106	16	1	123
34	Roberts		153	20	-	173
35	Rocker		13	7	-	20
36	Rudyard	275	131	29	-	160
37	Ryegate		3	-	-	3
38	Shawmut		23	4	-	27
39	Shelby	3,216	9	2	-	11
40	Sheridan	659	387	69	-	456
41	Silver Star		21	5	-	26
42	Silverbow		3	-	2	5
43	Simms	373	155	17	-	172
44	Somers	556	286	22	-	308
45	Springdale		1	-	-	1
46	Stevensville	1,553	1,473	226	5	1,704
47	Sun River	131	105	19	-	124
48	Three Forks	1,728	794	126	1	921
49	Trident		-	-	-	-
50	Turah		96	1	-	97

Sch. 29

Montana Customer Information- Natural Gas, 1/

City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
Twin Bridges	400	208	51	-	259
Valier	498	302	68	4	374
Vaughn	701	325	24	1	350
Victor	859	466	68	1	535
Walkerville		240	10	-	250
Warm Springs			1		1
West Glacier		105	39	3	147
Whitefish	5,032	3,366	461	4	3,831
Whitehall	1,044	669	106	3	778
Whitlash		2	-	-	2
Williamsburg		1	-	-	1
Willow Creek	209	96	12	-	108
Wolf Creek		51	27	1	79
Total	447,863	146,261	20,380	415	167,056

1/ Customer populations represent an average of the 12 month period from 01/01/05 through 12/31/05.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	4	6	5
4	Financial, Risk Mgmt. & Information Services	118	112	115
5	Human Resources & Administration	27	27	27
6	Utility Services & Division Administration	639	665	652
7	Regulatory Affairs	23	21	22
8	Transmission	159	164	162
9	Legal	7	7	7
10				
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	977	1,002	990
18				
19	1/ We have implemented a new methodology for computing employee counts in 2005. In the past, we have			
20	reported employees covered under Montana's benefit plans. In this year's computation, we determined what			
21	departments from Montana and South Dakota were charging labor to Montana, and prorated the employee			
22	counts accordingly. The Year Beginning counts were restated using the current methodology.			
23				
24	Consistent with prior years, part time employees have been converted to full-time equivalents.			

Sch. 31	MONTANA CONSTRUCTION BUDGET 2006 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	Three Rivers 161kV line	$1,501,135	$1,501,135
5	Electric Transmission - Harlowtown Transformer changeout	1,048,867	1,048,867
6	Billings 8th Street bank #2 changeout	1,000,000	1,000,000
7			
8			
9	All Other Projects < $1 Million Each MT	36,614,725	36,614,725
10	All Other Projects < $1 Million Each SD	9,407,721	
11	**Total Electric Utility Construction Budget**	49,572,448	40,164,727
12			
13	**Natural Gas Operations**		
14	Gas Transmission - Bison Creek pipeline loop	3,274,155	3,274,155
15	Gas Transmission - Cutbank pipeline loop	6,183,681	6,183,681
16			
17			
18	All Other Projects < $1 Million Each MT	10,071,260	10,071,260
19	All Other Projects < $1 Million Each SD	4,478,629	
20	**Total Natural Gas Utility Construction Budget**	24,007,725	19,529,096
21			
22	**Common**		
23	06 IT MTU NWE Asset Info/Mobile Data Com	1,095,000	1,095,000
24	All Other Projects < $1 Million Each MT	7,371,887	7,371,887
25	(Includes IS, Communications, Facilities, Cust Serv, Fleet)		
26	All Other Projects < $1 Million Each SD/NE	2,957,425	
27			
28	**Total Common Utility Construction Budget**	11,424,312	8,466,887
29			
30	CU4 capital additions - PPL invoice	4,995,065	4,995,065
31			
32	All Other Projects < $1 Million Each	-	-
33			
34			
35			
36	**Total Colstrip Unit 4 Construction Budget**	4,995,065	4,995,065
37	**TOTAL CONSTRUCTION BUDGET**	$89,999,550	$73,155,775

Sch. 32

MONTANA TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS

Transmission System-Sales and Transportation

	Peak Day of Month		Peak Day Volume (MMBTU's)		Monthly Volumes (MMBTU's)	
Month	Total Company	Montana	Total Company	Montana	Total Company, 2/	Montana, 3/
January					6,011,604	5,065,256
February					4,258,364	3,769,708
March					3,877,397	4,262,751
April		NOT AVAILABLE 1/			3,015,795	2,860,663
May					2,287,677	2,901,386
June					1,828,338	1,600,276
July					1,438,948	2,388,971
August					1,736,063	2,012,942
September					2,034,847	1,395,177
October					2,915,103	3,097,525
November					4,111,978	3,790,851
December					5,852,246	4,371,955
TOTAL					39,368,360	37,517,461

Distribution System-Sales and Transportation

	Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
Month	Total Company	Montana	Total Company	Montana	Total Company, 4/	Montana, 5/
January	3,624,348		205,627		3,829,975	3,624,348
February	2,546,742		146,997		2,693,739	2,546,742
March	2,130,011		130,986		2,260,997	2,130,011
April	1,806,300		193,808		2,000,108	1,806,300
May	1,237,025		186,326		1,423,351	1,237,025
June	865,180		150,442		1,015,622	865,180
July	517,606		61,446		579,052	517,606
August	420,172		135,033		555,205	420,172
September	502,488		106,317		608,805	502,488
October	905,941		196,582		1,102,523	905,941
November	1,308,596		174,150		1,482,746	1,308,596
December	2,730,281		207,721		2,938,002	2,730,281
TOTAL	18,594,690		1,895,435		20,490,125	18,594,690

Storage System-Sales and Transportation

	Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
	Total Company	Montana	Total Company 4/		Montana 5/	
Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
January			10,367	3,254,506		632,647
February			1,644	1,890,843		243,895
March			73,850	1,258,247	438,631	
April			564,968	514,943		115,295
May			1,394,446	56,603	698,851	
June			1,814,021	21,493		239,773
July			1,983,847	41,603	1,103,360	
August			1,461,626	26,497	352,822	
September			1,526,321	45,132		452,617
October			1,231,100	117,170	187,468	
November			516,388	764,576		301,058
December			112,831	2,773,389		1,050,370
TOTAL			10,691,409	10,765,002	2,781,132	3,035,655

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 MONTANA CORE NATURAL GAS SUPPLY				
	Supply Location	Last Year Volumes MMBTU	This Year Volumes MMBTU	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2	Canadian Pipeline	(250,000)		$4.2180	
3	Havre Pipeline	5,036,279		5.1340	
4	Pan Canadian Pipeline	7,149,911		5.1660	
5	Colorado Interstate Pipeline	(525,174)		5.2650	
6	Intra Montana Purchase	7,473,181		4.6920	
7	**TOTAL CORE SUPPLY LAST YEAR**	18,884,197	0	$5.0200	
8					
9	Canadian Pipeline		(488,733)		$1.9990
10	Havre Pipeline		6,194,469		7.7200
11	Pan Canadian Pipeline		9,179,769		7.0440
12	Colorado Interstate Pipeline		80,000		7.3560
13	Intra Montana Purchase		4,679,287		5.6670
14	**TOTAL CORE SUPPLY THIS YEAR**		19,644,792		$7.0690
15					
16	Note: Volumes reported reflect the net amount of volumes procured from the named supplier less				
17	volumes sold to that supplier.				
18					

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

2005

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (Mcf or Dkt)	Achieved Savings (Mcf or Dkt)	Difference
1							
2	2005 Residential Gas DSM Program	$492,278	zero	N/A	N/A	28,356	N/A
3	10-year life						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21	A program participant is a Montana residential gas customer who installs eligible						
22	energy conservation measures and receives financial incentives/rebates and/or						
23	weatherization measures.						
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**	$492,278				28,356	28,356

Sch. 35

MONTANA CONSUMPTION AND REVENUES - NATURAL GAS

	Description	Operating Revenues Current Year	Operating Revenues Previous Year	Dkt Sold Current Year	Dkt Sold Previous Year	Average Customers Current Year	Average Customers Previous Year
1	Sales of Natural Gas						
3	Residential	$ 135,393,012	$ 115,544,919	12,583,931	12,366,881	146,261	143,100
4	Commercial	67,018,377	56,904,414	6,209,725	6,028,552	20,320	19,929
5	Industrial Firm	2,036,824	1,798,428	180,722	195,742	335	348
6	Public Authorities	548,958	436,789	53,426	48,487	80	80
7	Interdepartmental	493,597	442,228	49,066	50,259	60	60
8	CNG Station	-	3,346	-	-	-	-
9	Sales to Other Utilities 2/	1,476,993	1,248,172	194,666	197,714	3	3
10	TOTAL SALES	206,967,761	176,378,296	19,271,536	18,887,635	167,059	163,520
11		Operating Revenues		Dkt Transported		Average Customers	
12–13		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
14	Transportation of Gas						
16	On System Transportation	$ 15,689,884	$ 14,379,745	19,132,521	17,938,722	241	234
17	Off System Transportation	495,186	866,850	1,763,875	2,526,858	1	15
18	Canadian Montana Pipeline	41,167	57,778				
19	TOTAL TRANSPORTATION	16,226,237	15,304,373	20,896,396	20,465,580	242	249

31 1/ Revenue and Dkts include unbilled and Canadian Montana Pipeline.

33 2/ Includes Sales to Other Utilities only, as compared to Schedule 9 which includes all Sales for Resale.

Natural Gas Universal System Benefits Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (Dkt)	Most recent program evaluation
1	Local Conservation					
2	E+ Residential Audit	307,000	-	307,000	15187	1994
3	NWE Promotion	-	-	0		
4	NWE Labor	17,448	-	17,448		
5	NWE Admin. Non-labor	12	-	12		
6	USB Interest & Svc Chg	(640)	-	(640)		
7	Market Transformation					
8	Research & Development					
9	Low Income					
10	Bill Assistance	1,172,588	-	1,172,588		n/a
11	Free Weatherization	585,000	-	585,000	25043	1994
12	Energy Share	150,000	-	150,000		n/a
13	2005 Gas USB Revenue Shortfall	(43,488)	-	(43,488)		
14	NWE Promotion	0	-	0		
15	NWE Labor	16,294	-	16,294		
16	NWE Admin. Non-labor	71	-	71		
17	USB Interest & Svc Chg	(3,669)	-	(3,669)		
18	Total	$ 2,200,616	$ -	$ 2,200,616		
19	Number of customers that received low income rate discounts				7963	
20	Average monthly bill discount amount ($/mo)				$ 12.27	
21	Average LIEAP-eligible household income				n/a	
22	Number of customers that received weatherization assistance				673 *(a)*	
23	Expected average annual bill savings from weatherization				37 Dkt	
24	Number of residential audits performed				574	

(a) Total of all homes weatherized in 2005 including electric and gas USB funds.

Montana Conservation & Demand Side Management Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2						
3						
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Other					
36						
37						
38						
39	Northwestern Energy's DSM program information is disclosed on Schedule 34. As such, disclosure					
40	here is not considered necessary.					
41						
42						
43						
44						
45						
46						
47						
48	Total					