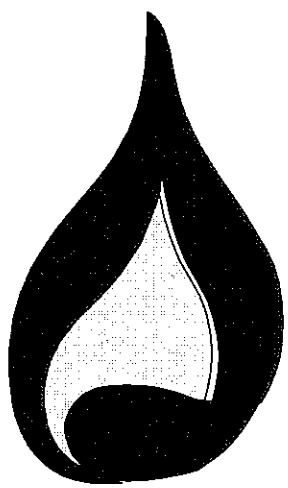
YEAR ENDING 2013

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 G. 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:

N/A

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See Northwestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
	President & Chief Executive Officer	Executive	Robert Rowe
	Vice President, Chief Financial Officer	Tax, Internal Audit, Credit Financial Planning and Analysis Controller and Treasury Functions Investor Relations and Corporate Finance Cash Management and Financial Applications Business Technology Energy Risk Management Flight Services, Executive Compensation	Brian Bird
	Vice President, General Counsel	Legal Services Corporate Secretary & Investor Services Records Management Risk Management FERC Compliance	Heather Grahame
	Vice President, Distribution Operations	Distribution Operations - MT/SD/NE Construction, Engineering, and Planning Organizational Development & Labor Relations Distribution Infrastructure Safety/Health/Environmental Services Support Services	Curt Pohl
	Vice President, Transmission	Regional System Planning and Engineering Gas Transmission & Storage Transmission Grid & Substation Operations Transmission Operations Reliability & Compliance Transmission Business Development and Analysis Organizational Performance & Asset Management	Michael Cashell
	Vice President, Supply	Production & Generation Operations Energy Supply Planning, Regulatory, & Marketing Energy Supply Long-Term Resources	John Hines
	Vice President, Government & Regulatory Affairs	Government & Regulatory Affairs	Patrick Corcoran
	Vice President, Customer Care, Communications & Human Resources	Corporate Communications Account and Analysis Infrastructure Systems and Support Customer Care Key Accounts/Customer Interaction Revenue Cycle Management Human Resources	Bobbi Schroeppel
	Chief Audit & Compliance Officer	Internal Audit Enterprise Risk	Michael Nieman
	Vice President, Controller	Financial Reporting Accounting Accounts Payable/Payroll Compensation and Benefits	Kendall Kliewer

Reflects active officers as of December 31, 2013.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 91,618**	**97.48%**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including CMP & HPC) Propane Utility		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		**$ 2,365**	**2.52%**
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
NorthWestern Investments, LLC	Holds non-utility assets		
Risk Partners Assurance, Ltd.	Captive insurance company		
Mountain States Transmission Intertie, LLC	Will hold new transmission infrastructure assets		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Total Corporation		**$ 93,983**	**100.00%**

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Controller	Includes the following departments: Controller, Accounting Accounts Payable, Payroll, Financial Reporting and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$17,035,790	77.56%	$4,929,035
Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Corp Communications & Contributions, Human Resources and Print Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	21,719,562	74.58%	7,401,607
Legal Department	Includes the following departments: Chief Legal, Record Services, Risk Mgmt	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	9,455,463	80.19%	2,335,727
Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, Business Technology Applications, Security, Data Center, Project Management & Asset Control and Capital Related Exp.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	15,268,755	74.04%	5,354,352
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research, Government Affairs, Reg Support Services, Community Relations & Public Affairs.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	3,979,719	83.49%	787,222
Executive Department	Includes the following departments: CEO, and Board of Directors	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	2,410,382	71.46%	962,612
Audit & Controls	Includes the following departments: Internal Audit and Enterprise Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	765,003	73.00%	282,946
Distribution	Includes the following departments: Sioux Falls Facilities and Mail Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	512,372	73.00%	189,508
TOTAL			$71,147,046	76.18%	$22,243,009

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	**Total Nonutility Subsidiaries**			$0		$0
5	**Total Nonutility Subsidiaries Revenues**			$0		
6						
7						
8						
9	**Utility Subsidiaries**					
10						
11	**Total Utility Subsidiaries**			$0		$0
12	Canadian-Montana Pipeline Corporation	Natural gas pipeline	Contract rate	$145,641		
13	Havre Pipeline Company, LLC	Natural gas gathering	Tariffed rate	418,151		
14	**Total Utility Subsidiaries Revenues**			$563,792		
15	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

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						
5						
6	**Total Nonutility Subsidiaries**			$0		$0
7	**Total Nonutility Subsidiaries Expenses**			$0		
8						
9						
10						
11	**Utility Subsidiaries**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	$41,700	11.4%	$41,700
14						
15	**Total Utility Subsidiaries**			$41,700		$41,700
16	**Total Utility Subsidiaries Expenses**			$391,655		
17	**TOTAL AFFILIATE TRANSACTIONS**			$41,700		$41,700

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	$ 294,370,896	$ 94,131,186	$ 200,239,710	$ 182,900,425	9.48%
3						
4	**Total Operating Revenues**	294,370,896	94,131,186	200,239,710	182,900,425	9.48%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	192,212,371	71,616,019	120,596,352	117,687,888	2.47%
9	402 Maintenance Expense	10,232,490	1,717,773	8,514,717	7,113,177	19.70%
10	403 Depreciation Expense	20,242,276	5,944,931	14,297,345	13,733,750	4.10%
11	404-405 Amort. & Depletion of Gas Plant	4,108,063	241,670	3,866,393	2,061,641	87.54%
12	406 Amort. of Plant Acquisition Adj.	(1,321,778)	(1,321,778)	-	-	-
13	407.3 Regulatory Amortizations - Debit	5,223,429	2,576,497	2,646,932	7,016,519	-62.28%
14	407.4 Regulatory Amortizations - Credit	(4,059,004)	(113,288)	(3,945,716)	(5,141,564)	23.26%
15	408.1 Taxes Other Than Income Taxes	29,784,504	2,069,658	27,714,846	25,563,041	8.42%
16	409.1 Income Taxes-Federal	(2,865,660)	(2,911,003)	45,343	841,263	-94.61%
17	-Other	(521,798)	(543,349)	21,551	(1,200)	>300.00%
18	410.1 Deferred Income Taxes-Dr.	68,014,501	15,838,022	52,176,479	65,699,431	-20.58%
19	411.1 Deferred Income Taxes-Cr.	(60,825,521)	(9,616,491)	(51,209,030)	(68,502,742)	25.25%
20	411.4 Investment Tax Credit Adj.	(29,012)	(29,012)	-	-	-
21						
22	**Total Operating Expenses**	260,194,861	85,469,649	174,725,212	166,071,204	5.21%
23	**NET OPERATING INCOME**	$ 34,176,035	$ 8,661,537	$ 25,514,498	$ 16,829,221	51.61%

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
1						
2	**Core Distribution Business Units**					
3	**(DBUs)**					
4	440 Residential	$ 162,739,295	$ 51,042,215	$ 111,697,080	$ 102,161,589	9.33%
5	442.1 Commercial	$ 88,736,091	32,323,098	56,412,993	51,616,810	9.29%
6	442.2 Industrial Firm	$ 1,083,842	-	1,083,842	1,012,511	7.04%
7	445 Public Authorities	$ 513,312	-	513,312	460,505	11.47%
8	448 Interdepartmental Sales	$ 507,287	-	507,287	438,189	15.77%
9	491.2 CNG Station	-	-	-	-	-
10						
11	**Total Sales to Core DBUs**	253,579,827	83,365,313	170,214,514	155,689,604	9.33%
12						
13	447 Sales for Resale	2,839,575	-	2,839,575	1,798,682	57.87%
14						
15	**Total Sales of Natural Gas**	256,419,402	83,365,313	173,054,089	157,488,286	9.88%
16	496.1 Provision for Rate Refunds	(153,755)	-	(153,755)	1,110,553	-113.84%
17						
18	**Total Revenue Net of Rate Refunds**	256,265,647	83,365,313	172,900,334	158,598,839	9.02%
16		0				
17	**Transportation**					
18						
19	489 Transportation (inc. CMP)	33,546,638	10,185,641	23,360,997	21,289,330	9.73%
20	495 Off System Storage		-	-	-	-
21						
22	**Total Revenues From Transportation**	33,546,638	10,185,641	23,360,997	21,289,330	9.73%
23						
24	**Other Operating Revenue**					
25						
26	Miscellaneous Revenues	4,558,612	580,232	3,978,379	3,012,256	32.07%
27						
28	**Total Other Operating Revenue**	4,558,612	580,232	3,978,379	3,012,256	32.07%
29	**TOTAL OPERATING REVENUE**	$ 294,370,896	$ 94,131,186	$ 200,239,710	$ 182,900,425	9.48%
30						
31						
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.					
34	This line consists of sales for resale and sales to other utilities, as compared to Schedule 35,					
35	which only reflects sales to other utilities.					
36						
37						

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	728 Liquefied Petroleum Gas	$ -	$ -	$ -	$ -	-
4	735 Miscellaneous Production Expenses	457	457	0	-	-
5	**Total Operation-Gas Raw Materials**	457	457	0	-	-
6						
7	**Gas Raw Materials-Maintenance**					
8	741 Structures & Improvements	40,270	40,270	-	-	-
9	**Total Maintenance-Gas Raw Materials**	40,270	40,270	-	-	-
10	**Total Gas Raw Materials**	40,728	40,727	0	-	-
11	**Production Expenses**					
12						
13	**Production & Gathering-Operation**					
14	750 Supervision & Engineering	257,096	-	257,096	260,029	-1.13%
15	751 Maps & Records	-	-	-	-	-
16	752 Gas Wells Expenses	1,096,659	-	1,096,659	396,770	176.40%
17	753 Field Lines Expenses	-	-	-	-	-
18	754 Field Compressor Station Expense	715,371	-	715,371	217,166	229.41%
19	755 Field Comp. Station Fuel & Power	320,606	-	320,606	81,188	294.89%
20	756 Field Meas. & Reg. Station Expense	27,497	-	27,497	16,592	65.72%
21	757 Dehydration Expense	7,758	-	7,758	115,991	-93.31%
22	758 Gas Well Royalties	1,097,954	-	1,097,954	157,026	>300.00%
23	759 Other Expenses	1,476,022	-	1,476,022	951,741	55.09%
24	760 Rents	184,962	-	184,962	16,381	>300.00%
25	**Total Oper.-Production & Gathering**	5,183,925	-	5,183,925	2,212,886	134.26%
26						
27	**Production Maintenance**					
28	762 Maint. of Gathering Structures	102	-	102	118	-13.34%
29	763 Maint. of Producing Gas Wells	43,516	-	43,516	54,572	-20.26%
30	764 Maint. of Field Lines	13,454	-	13,454	25,121	-46.44%
31	765 Maint. of Field Compressor Stations	155,312	-	155,312	84,157	84.55%
32	766 Maint. of Field Meas. & Reg. Stations	2,675	-	2,675	1,653	61.84%
33	767 Maint. of Purification Equipment	444	-	444	5,184	-91.43%
34	769 Maint. of Other Equipment	35,114	-	35,114	17,763	97.68%
35	**Total Maintenance - Production**	250,617	-	250,617	188,568	32.91%
36	**TOTAL Natural Gas Production & Gatthering**	5,434,543	-	5,434,543	2,401,453	126.30%
37						
38	**Other Gas Supply Expense-Operation**					
39	800 NG Wellhead Purchases	60,463,237	-	60,463,237	59,268,859	2.02%
40	803 NG Transmission Line Purchases	683,128	-	683,128	1,154,081	-40.81%
41	805 Other Gas Purchases	58,416,978	56,786,693	1,630,285	89,318	>300.00%
42	805 Purchased Gas Cost Adjustments		-	-	-	-
43	805 Incremental Gas Cost Adjustments	-	-	-	-	-
44	805 Deferred Gas Cost Adjustments	-	-	-	-	-
45	806 Exchange Gas	-	-	-	-	-
46	807 Well Expenses-Purchased Gas	1,762,514	22,238	1,740,276	2,852,877	-39.00%
47	807 Purch. Gas Meas. Stations-Oper.	-	-	-	-	-
48	807 Purch. Gas Meas. Stations-Maint.	-	-	-	-	-
49	807 Purch. Gas Calculations Expenses	-	-	-	-	-
50	808 Other Purchased Gas Expenses	-	-	-	-	-
51	808 Gas Withdrawn from Storage -Dr.	1,973,553	-	1,973,553	8,458,094	-76.67%
52	809 Gas Delivered to Storage -Cr.	-	-	-	-	-
53	810 Gas Used-Comp. Station Fuel-Cr.	-	-	-	-	-
54	811 Gas Used-Products Extraction-Cr.	-	-	-	-	-
55	812 Gas Used-Other Utility Oper.-Cr.	-	-	-	-	-
56	813 Other Gas Supply Expenses	-	-	-	-	-
57	**Total Other Gas Supply Expenses**	123,299,410	56,808,931	66,490,479	71,823,229	-7.42%
58	**Total Production Expenses**	128,733,952	56,808,931	71,925,022	74,224,682	-3.10%

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	42,122	-	42,122	49,935	-15.65%
5	815 Maps & Records	40	-	40	123	-67.43%
6	816 Wells	230,794	-	230,794	260,112	-11.27%
7	817 Lines	26,138	-	26,138	65,474	-60.08%
8	818 Compressor Station	271,743	-	271,743	299,204	-9.18%
9	819 Compressor Station Fuel & Power	-	-	-	-	-
10	820 Measuring & Regulating Station	22,426	-	22,426	42,902	-47.73%
11	821 Purification	94,190	-	94,190	92,799	1.50%
12	824 Other Expenses	94,666	-	94,666	91,746	3.18%
13	825 Storage Well Royalties	93,313	-	93,313	112,554	-17.09%
14	826 Rents	-	-	-	-	-
15	**Total Operation-Underground Storage**	875,432	-	875,432	1,014,849	-13.74%
16						
17	**Underground Storage-Maintenance**					
18	830 Supervision & Engineering	-	-	-	-	-
19	831 Structures & Improvements	63,811	-	63,811	96,762	-34.05%
20	832 Reservoirs & Wells	14,771	-	14,771	11,874	24.40%
21	833 Lines	21,484	-	21,484	7,812	175.00%
22	834 Compressor Station Equipment	89,091	-	89,091	126,970	-29.83%
23	835 Meas. & Reg. Station Equipment	576	-	576	23,188	-97.51%
24	836 Purification Equipment	24,815		24,815	-	-
25	837 Other Equipment	1,303	-	1,303	18,617	-93.00%
26	**Total Maintenance-Underground Storage**	215,851	-	215,851	285,223	-24.32%
27	**Total Underground Storage Expenses**	1,091,283	-	1,091,283	1,300,072	-16.06%
28	**Transmission Expenses**	-				
29	**Transmission-Operation**					
30	850 Supervision & Engineering	2,856,135	9,743	2,846,392	2,734,777	4.08%
31	851 System Control & Load Dispatching	1,120,640	-	1,120,640	1,133,644	-1.15%
32	853 Compressor Station Labor & Expense	678,564	-	678,564	602,338	12.65%
33	855 Other Fuel & Power for Comp. Stat.	-	-	-	-	-
34	856 Mains	1,055,310	34,606	1,020,704	1,093,789	-6.68%
35	857 Measuring & Regulating Station	611,635	5,868	605,767	612,888	-1.16%
36	858 Transmission & Comp.-By Others	-	-	-	-	-
37	859 Other Expenses	1,748,272	16,966	1,731,306	1,365,208	26.82%
38	860 Rents	-	-	-	-	-
39	**Total Operation-Transmission**	8,070,556	67,183	8,003,373	7,542,644	6.11%
40	**Transmission-Maintenance**					
41	861 Supervision & Engineering	84,233	-	84,233	98,540	-14.52%
42	862 Structures & Improvements	92,013	-	92,013	105,576	-12.85%
43	863 Mains	977,408	6,284	971,124	1,175,635	-17.40%
44	864 Compressor Station Equipment	1,265,372	-	1,265,372	541,446	133.70%
45	865 Meas. & Reg. Station Equipment	443,589	12,952	430,637	384,836	11.90%
46	867 Other Equipment	27,255	-	27,255	18,725	45.56%
47	**Total Maintenance-Transmission**	2,889,870	19,236	2,870,634	2,324,758	23.48%
48	**Total Transmission Expenses**	10,960,426	86,419	10,874,007	9,867,402	10.20%
		-				

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	3,387,674	1,372,560	2,015,114	1,927,462	4.55%
4	871 Load Dispatching	148,811	148,811	-	-	-
5	872 Compressor Station Labor & Expense	-	-	-	-	-
6	873 Compressor Station Fuel and Power	-	-	-	-	-
7	874 Mains and Services	5,996,480	2,714,706	3,281,774	2,411,613	36.08%
8	875 Meas. & Reg. Station-General	416,439	224,140	192,299	195,570	-1.67%
9	876 Meas. & Reg. Station-Industrial	-	-	-	-	-
10	877 Meas. & Reg. Station-City Gate	229,588	23,983	205,605	171,797	19.68%
11	878 Meter & House Regulator	2,564,608	984,947	1,579,661	1,517,807	4.08%
12	879 Customer Installations	2,836,326	326,950	2,509,376	2,524,179	-0.59%
13	880 Other Expenses	1,734,925	506,879	1,228,046	542,632	126.31%
14	881 Rents	4,317	-	4,317	3,195	35.13%
15	**Total Operation-Distribution**	17,319,168	6,302,976	11,016,192	9,294,255	18.53%
16	**Distribution-Maintenance**					
17	885 Supervision & Engineering	1,313,194	309,012	1,004,182	847,446	18.50%
18	886 Structures & Improvements			-	-	-
19	887 Mains	1,046,907	387,629	659,278	843,369	-21.83%
20	889 Meas. & Reg. Station Exp.-General	242,507	126,152	116,355	86,517	34.49%
21	890 Meas. & Reg. Station Exp.-Industrial	-	-	-	-	-
22	891 Meas. & Reg. Station Exp.-City Gate	125,433	125,433	-	-	-
23	892 Services	1,494,016	322,387	1,171,629	519,632	125.47%
24	893 Meters & House Regulators	1,313,914	263,763	1,050,151	983,833	6.74%
25	894 Other Equipment	-	-	-	-	-
26	**Total Maintenance-Distribution**	5,535,971	1,534,376	4,001,595	3,280,797	21.97%
27	**Total Distribution Expenses**	22,855,139	7,837,352	15,017,787	12,575,052	19.43%
28	**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**					
30	901 Supervision	-	-	-	-	-
31	902 Meter Reading	1,453,573	820,600	632,973	590,638	7.17%
32	903 Customer Records & Collection	3,027,553	581,490	2,446,063	2,554,531	-4.25%
33	904 Uncollectible Accounts	1,137,151	395,074	742,077	521,949	42.17%
34	905 Miscellaneous Customer Accounts	28,012	28,065	(53)	912	-105.76%
35	**Total Customer Accounts Expenses**	5,646,289	1,825,229	3,821,060	3,668,030	4.17%
36						
37	**Customer Service & Information Expenses**					
38	**Customer Service-Operation**					
39	907 Supervision	-	-	-	-	-
40	908 Customer Assistance	2,573,433	1,090,556	1,482,877	1,462,848	1.37%
41	909 Inform. & Instructional Advertising	472,523	129,434	343,089	386,456	-11.22%
42	910 Misc. Customer Service & Inform.	-	-	-	-	-
43	**Total Customer Service & Information Exp.**	3,045,956	1,219,990	1,825,966	1,849,304	-1.26%
44						
45	**Sales Expenses**					
46	**Sales-Operation**					
47	911 Supervision	-	-	-	-	-
48	912 Demonstrating & Selling	-	-	-	-	-
49	913 Advertising	307,551	109,466	198,085	112,156	76.62%
50	916 Miscellaneous Sales	-	-	-	-	-
51	**Total Sales Expenses**	307,551	109,466	198,085	112,156	76.62%

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	13,341,236	3,656,415	9,684,821	8,746,295	10.73%
4	921 Office Supplies & Expenses	4,031,587	1,396,273	2,635,314	2,631,783	0.13%
5	922 Administrative Exp. Transferred-Cr.	(3,057,741)	(1,395,905)	(1,661,836)	(1,838,638)	9.62%
6	923 Outside Services Employed	1,981,676	517,840	1,463,836	1,351,829	8.29%
7	924 Property Insurance	342,346	92,225	250,121	263,723	-5.16%
8	925 Legal & Claim Department	2,948,475	612,292	2,336,183	2,231,800	4.68%
9	926 Employee Pensions & Benefits	1,356,853	(206,148)	1,563,001	887,278	76.16%
10	928 Regulatory Commission Expenses	186,169	-	186,169	112,289	65.79%
11	930 Miscellaneous General Expenses	6,305,899	304,308	6,001,591	5,083,258	18.07%
12	931 Rents	1,027,128	304,488	722,640	700,919	3.10%
13	**Total Operation-Admin. & General**	28,463,628	5,281,788	23,181,840	20,170,536	14.93%
14	**Admin. & General - Maintenance**					
15	935 General Plant	1,299,909	123,890	1,176,019	1,033,831	13.75%
16	**Total Admin. & General Expenses**	29,763,537	5,405,678	24,357,859	21,204,367	14.87%
17	**TOTAL OPER. & MAINT. EXPENSES**	$ 202,444,861	$ 73,333,792	$ 129,111,069	$ 124,801,065	3.45%
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	$2,009,470	$1,824,006	10.17%
3	Property Taxes	24,067,799	22,460,837	7.15%
4	Crow Tribe RR and Utility Tax	91,820	90,296	1.69%
5	Blackfoot Possessoray Tax	308,624	307,837	0.26%
6	City Tax	4,545	3,435	32.31%
7	Consumer Counsel	127,942	113,642	12.58%
8	Public Service Commission	477,414	370,773	28.76%
9	Heavy Highway Use	6,594	4,052	62.73%
10	Vehicle Use Taxes	96,244	90,374	6.50%
11	Gas Production Taxes	331,467	118,493	179.74%
12	Oil & Gas Royalty Taxes	131,345	112,260	17.00%
13	Delaware Franchise Tax	40,745	46,807	-12.95%
14				
15				
16				
17	**Canadian Taxes**			
18	Ad Valorem	20,837	20,230	3.00%
19				
20				
21				
22				
23	**TOTAL TAXES OTHER THAN INCOME**	$27,714,846	$25,563,041	8.42%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A & A ASPHALT MAINTENANCE	Asphalt Services	97,975
2	ALME CONSTRUCTION, INC.	Construction	357,483
3	ALSTOM GRID INC	Software Support Services	960,104
4	ALSTOM GRID INC	Software Support Services	283,746
5	AMERICAN INNOVATIONS INC	Software Support Services	147,874
6	ARCADIS US INC	Engineering Services	1,608,602
7	AREA STEEL	Construction	228,512
8	ASCEND ANALYTICS LLC	Hydro Expert Analysis	352,576
9	ASPEN CONSULTING & TESTING INC	Environmental Consultants	77,490
10	ASPLUNDH TREE EXPERT COMPANY	Tree Trimming	4,927,233
11	ASSOCIATED ARBORISTS	Vegetation Management	2,013,520
12	AUTOMOTIVE RENTALS INC	Fleet Management	8,775,479
13	BALHOFF & WILLIAMS LLC	Legal Services	133,601
14	BART ENGINEERING COMPANY	Engineering Services	471,085
15	BECKLER CONSTRUCTION	Construction	87,202
16	BIG COUNTRY ENERGY SERVICES LLC	Construction	763,321
17	BIG SKY WATER HAULING LLC	Water Hauling Services	99,695
18	BILL FIELD TRUCKING INC	Hauling Services	368,663
19	BISON ENGINEERING INC	Environmental Engineering Services	115,291
20	BOZEMAN GREEN BUILD	Solar System Installation	79,894
21	BROWNING, KALECZYC, BERRY & HOVAN	Legal Services	176,658
22	BRUNSWICK GROUP LLC	Financial, Investor and Public Relations Consultant	100,000
23	CENTRAL AIR SERVICE INC	Aerial Pilot Services	331,349
24	CENTRAL COPTERS INC	Flight Services	119,767
25	CESSNA AIRCRAFT COMPANY	Aircraft Maintenance	286,378
26	COMPLETE CAREER CENTER INC	Temporary Employment Services	115,895
27	CONTINENTAL STEEL WORKS	Fabrication Services	641,948
28	COP CONSTRUCTION LLC	Construction	87,840
29	CORPORATE EXECUTIVE BOARD	Organizational Development Consultant	88,808
30	CREDIT SUISSE SECURITIES (USA)	Legal Services	215,949
31	CRIST, KROGH, BUTLER & NORD LLC	Legal Services	111,022
32	CROWLEY FLECK	Legal Services	103,923
33	CTA ARCHITECTS ENGINEERS	Energy Conservation Consultants	158,148
34	CYME INTERNATIONAL T & D INC	Construction	92,627
35	DAKOTA HIGH VOLTAGE TESTING	Electric System Testing and Maintenance	157,197
36	DAVEY RESOURCE GROUP	Field Surveyors	822,461
37	DAVEY TREE SURGERY COMPANY	Tree Trimming	2,020,564
38	DELOITTE & TOUCHE LLP	Audit Services	1,527,060
39	DEPT OF HEALTH & HUMAN SERVICES	Weatherization Program Services	1,972,777
40	DEVLIN ENTERPRISES	Lobbying Services	84,172
41	DGR ENGINEERING	Engineering Services	232,071
42	DHC INC	Boring Services	102,388
43	DISTRIBUTION CONSTRUCTION CO	Gas Pipeline Construction	1,351,851
44	DONNES INC	Construction	94,200
45	DORSEY & WHITNEY LLP	Legal Services	651,875
46	DOWL HKM	Engineering Services	81,426
47	EDM INTERNATIONAL INC	Anchor Rod Inspection Services	615,908
48	ELM LOCATING & UTILITY SERVICE	Locating Services and Excavation Notifications	2,485,178
49	ENERGY SHARE OF MONTANA	USBC Services	665,045
50	EXPRESS SERVICES INC	Temporary Employment Services	78,792
51	FAIRBANKS MORSE ENGINE	Construction	125,081
52	FALLS CONSTRUCTION COMPANY	Construction	126,678
53	FENCECRAFTERS HELENA INC	Fencing Installation	145,230
54	FISHNET SECURITY INC	Software Support Services	1,072,659
55	FLUID MARKET STRATEGIES	Energy Conservation Consultants	702,785
56	FLYNN WRIGHT INC	Advertising Services	1,484,974
57	FORBES TATE LLC	Regulatory Consultants	100,000
58	GARTNER INC	Information Technology Consulting	128,130
59	GARY INCE CONSTRUCTION INC	Construction	698,581
60	GILLESPIE PRUDHON & ASSOCIATES	Telecommunications Engineers	145,952
61	GREATER GALLATIN CONTRACTORS	Landscape Repair Services	82,692
62	H & H ASPHALT & MAINTENANCE INC	Asphalt Services	133,995
63	H & H CONTRACTING INC	Concrete and Asphalt Services	659,036
64	HAIDER CONSTRUCTION INC	Backhoe Services	310,649

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
65	HDR ENGINEERING INC	Engineering Services	934,310
66	HEALTH FITNESS CORPORATION	Employee Wellness Program Management	331,014
67	HEATH CONSULTANTS INC	Gas Leak Surveys	421,405
68	HIGH MARK MEDIA	Marketing Services	81,485
69	HOWALT MCDOWELL INSURANCE INC	Benefits Consultants	100,626
70	INDEPENDENT INSPECTION COMPANY	Electric Line Inspection	2,545,024
71	INTEGRITY ELECTRIC	Energy Conservation Contractors	77,225
72	INTERGRAPH CORPORATION	Software Consultants	448,338
73	JACOBSEN TREE EXPERTS	Tree Trimming	786,337
74	JARES FENCE COMPANY INC	Fencing Installation	87,956
75	JENSEN'S TREE SERVICE INC	Tree Trimming	162,021
76	JERKE CONSTRUCTION CO	Construction	118,389
77	JONES DAY	Legal Services	107,352
78	JONES PLUMBING & HEATING INC	Construction	86,674
79	JORDAN CONTRACTING INC	Construction	175,088
80	JSSI JET SUPPORT SERVICES INC	Flight Services	191,350
81	KC HARVEY ENVIRONMENTAL LLC	Environmental Consultants	238,515
82	KELLY SERVICES INC	Engineering Services	89,293
83	KEMA SERVICES INC	USB and DSM Programs and Services	7,444,766
84	KM CONSTRUCTION CO INC	Construction	99,959
85	KNIFE RIVER	Construction	254,815
86	KRONEBUSCH ELECTRIC INC	Construction	85,027
87	LANDS ENERGY CONSULTING	Energy Consultants	195,583
88	LEONARD,STREET & DEINARD	Legal Services	197,725
89	LOCKMER PLUMBING HEATING & UTILITIES	Gas Meter Relocations	113,613
90	LODGEPOLE LAND SERVICES LLC	Construction	84,616
91	MANAGEMENT APPLICATIONS CONSULTING	Regulatory Consultants	107,863
92	MAPPCOR	Electric Reliability Services	379,292
93	MARKOVICH CONSTRUCTION INC	Construction	203,316
94	MCKINSTRY ESSENTION	Energy Conservation Consultants	101,494
95	MECHANICAL TECHNOLOGY INC	Construction	106,683
96	MERIDIAN IT INC	Information Technology Services	612,406
97	MICHAELS FENCE & SUPPLY INC	Fencing Installation	87,805
98	MICROSOFT LICENSING GP	Computer Licensing	577,975
99	MICROSOFT SERVICES	Computer Maintenance	99,552
100	MOODY'S INVESTORS SERVICES	Debt Rating Services	218,500
101	MOSAIC ARCHITECTURE	Architects	728,358
102	MOUNTAIN POWER CONSTRUCTION CO	Construction	10,886,391
103	MOUNTAIN WEST HOLDING COMPANY	Construction	257,014
104	MT DEPT OF HEALTH & HUMAN SERVICES	USBC Services	283,811
105	NAES CORPORATON	Construction	360,551
106	NAT'L CENTER FOR APPROPRIATE TECHNOLOGY	Conservation Program Consultants	1,261,481
107	NATURAL GAS SERVICES INC	Gas Servicemen	107,826
108	NAVIGANT CONSULTING INC	Transmission System Consultants	273,726
109	NETWORK MAPPING INC	Aerial Surveyors	597,136
110	NEXANT INC	Energy Efficiency Consultants	98,645
111	NORLEY CONSULTING	Gas Compressor Consultant	154,891
112	NORTHWEST DYNAMICS INSPECTION	Safety Inspections	78,838
113	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,825,894
114	NORTHWEST TOWER	Construction	301,123
115	OLSON LAND SERVICES	Real Estate Services	160,867
116	OMIMEX CANADA LTD	Gas Lease Operating Expenses	805,316
117	OPEN ACCESS TECHNOLOGY INT'L INC	Software Support Services	391,119
118	OSMOSE INC	Construction	715,241
119	P2 ENERGY SOLUTIONS INC	Computer System Implementation	195,581
120	PACER ENERGY LLC	Due Diligence for Gas Acquisition	125,627
121	PALMER ELECTRIC TECHNOLOGY	Electric Facilities Contractor	95,321
122	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	12,711,659
123	PERKINS COIE	Legal Services	1,506,698
124	POWER ENGINEERS INCORPORATED	Engineering Services	1,174,450
125	POWERPLAN INC	Software Implementation Support Services	343,593
126	PRATT & WHITNEY POWER SYSTEMS	Construction	290,825
127	R&R ELECTRIC INC	Construction	93,592
128	RML INCORPORATED	Boring Services	418,225
129	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	24,952,194

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
130	ROD TABBERT CONSTRUCTION INC	Construction	558,017
131	ROUNDS BROTHERS TRENCHING	Boring Services	295,175
132	S & C ELECTRIC COMPANY	Construction	186,128
133	SBW CONSULTING INCORPORATED	DSM Program Evaluation	387,411
134	SCENIC CITY PUMPING	Construction	114,866
135	SHUMAKER TRUCKING & EXCAVATING	Excavation Contractor	526,838
136	SKADDEN, ARPS, SLATE, MEAGHER	Legal Services	2,927,282
137	SOLAR PLEXUS	USB and DSM Programs and Services	88,635
138	SPHERION STAFFING	Temporary Employment Services	338,697
139	STANDARD & POOR'S FINANCIAL SERVICES	Debt Rating Services	255,565
140	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	650,603
141	STENSON MANAGEMENT CONSULTING	Effective Leadership Consultant	109,429
142	STINSON MORRISON LLP	Legal Services	263,129
143	STONE & WEBSTER	Power Generations Development	971,975
144	SULLIVAN, TABARACCI & RHOADES, PC	Legal Services	180,988
145	SUNDANCE SOLAR SYSTEMS	Solar System Installation	127,222
146	SUSSEX ECONOMIC ADVISORS LLC	Regulatory Consultants	89,720
147	THE BLACKSTONE GROUP	Hydro Acquisition Fairness Opinion	1,257,936
148	THE BOLDT COMPANY	Power Plant Construction	868,043
149	THE ELECTRIC COMPANY OF SOUTH DAKOTA	Construction	296,527
150	THE ENERGY AUTHORITY INC	Scheduling and Dispatch	598,585
151	THE L E MYERS CO	Storm Damage Restoration	1,987,722
152	THIRSTY LAKE SOLAR	Solar System Installation	75,870
153	TODD O BRUESKE CONSTRUCTION	Construction	315,022
154	TONY LASLOVICH CONSTRUCTION	Construction	114,218
155	TOWER SYSTEMS INC	Construction	291,192
156	TOWERS WATSON DATA SERVICES	Compensation Consultants	88,342
157	TRADEMARK ELECTRIC INC	Construction	309,014
158	TRI-COUNTY MECHANICAL & ELECTR	Construction	123,716
159	UNDERGROUND CONSTRUCTION	Construction	161,100
160	UTILITIES UNDERGROUND LOCATION	Locating Services and Excavation Notifications	154,052
161	UTILITY DATA CONTRACTORS INC	Data Entry Services	239,761
162	VARSITY CONTRACTORS INC	Janitorial Services	302,938
163	VERTEX	Billing Services and System Implementation	6,124,269
164	WASHINGTON FORESTRY CONSULTANTS	Forestry Consultants	571,189
165	WASLEY EXCAVATING	Construction	200,859
166	WATER & ENVIRONMENTAL TECHNOLOGY	Environmental Engineering Services	298,652
167	WILLIAMSON FENCING INC	Construction	113,779
168	WINSTON & STRAWN LLP	Legal Services	187,381
169	WOOD GROUP POWER PLANT SERVICE	Construction	442,914
170	WOOD GROUP PRATT & WHITNEY LLC	Turbine Repair Services	1,114,316
171	WRIGHT AND SUDLOW INC	Construction	711,761
172	ZACHA UNDERGROUND CONSTRUCTION	Construction	104,058
173			
174			
175			
176			
177	Total of Payments Set Forth Above		$ 147,713,348

1/ This schedule includes payments for professional services over $75,000.

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
1				
2				
3	There are three employee political action committees			
4	(PAC)s:			
5				
6	a. Employees of NorthWestern Corporation			
7	(NorthWestern Energy) PAC;			
8				
9	b. NorthWestern Energy Employees PAC; and			
10				
11	c. NorthWestern Public Service Employees PAC.			
12				
13	All of the money contributed by members is			
14	dedicated to support political candidates. No			
15	company funds may be spent in support of a			
16	political candidate. Nominal administrative costs			
17	for such things as duplicating, postage, and meeting			
18	expenses are paid by the company as provided by			
19	law. These costs are charged to shareholder			
20	expense.			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36	**TOTAL Contributions**	$ -	$ -	

Sch. 14	Pension Costs 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: ______________		
4	Annual Contribution by Employer: Variable	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	$ 545,833,926	$ 477,929,697	14.21%
8	Service cost	12,287,637	10,435,096	17.75%
9	Interest cost	20,553,581	21,372,539	-3.83%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	(49,399,148)	54,198,276	-191.15%
13	Acquisition	-	-	-
14	Benefits paid	(19,112,440)	(18,101,682)	-5.58%
15	Benefit obligation at end of year	$ 510,163,556	$ 545,833,926	-6.54%
16	**Change in Plan Assets**	-	-	
17	Fair value of plan assets at beginning of year	$ 419,255,762	$ 383,101,559	9.44%
18	Actual return on plan assets	48,588,779	43,755,885	11.05%
19	Acquisition	-	-	-
20	Employer contribution	10,500,000	10,500,000	-
21	Plan participants' contributions	-	-	-
22	Benefits paid	(19,112,440)	(18,101,682)	-5.58%
23	Fair value of plan assets at end of year	$ 459,232,101	$ 419,255,762	9.54%
24	**Funded Status**	$ (50,931,455)	$ (126,578,164)	59.76%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (50,931,455)	$ (126,578,164)	59.76%
30	**Weighted-average Assumptions as of Year End**	-	-	
31	Discount rate	4.75%	3.80%	25.00%
32	Expected return on plan assets	7.00%	7.00%	-
33	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 12,287,637	$ 10,435,096	17.75%
36	Interest cost	20,553,581	21,372,539	-3.83%
37	Expected return on plan assets	(28,886,294)	(26,637,374)	-8.44%
38	Amortization of prior service cost	246,361	246,361	-
39	Recognized net actuarial gain	11,138,542	8,314,967	33.96%
40	Net periodic benefit cost (SEC Basis)	$ 15,339,827	$ 13,731,589	11.71%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**	-	-	
42	Pension Costs	$ 10,500,000	$ 29,410,000	-64.30%
43	Pension Costs Capitalized	2,161,868	6,292,692	-65.64%
44	Accumulated Pension Asset (Liability) at Year End	$ (50,931,455)	$ (126,578,164)	59.76%
45	**Number of Company Employees:**			
46	Covered by the Plan	3,061	3,100	-1.26%
47	Not Covered by the Plan 2/	342	268	27.61%
48	Active	899	947	-5.07%
49	Retired	1,394	1,359	2.58%
50	Deferred Vested Terminated	768	794	-3.27%

1/ NorthWestern Corporation has a separate pension plan covering South Dakota and Nebraska employees that is not reflected above.

2/This plan was closed to new entrants effective 10/03/08.

Sch. 14a	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: Variable	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	$ 253,146,989	$ 218,194,855	13.81%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 7,790,683	$ 7,164,928	8.73%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 312,279,277	$ 253,146,989	23.36%
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	401(k) Plan Defined Contribution Costs	$ 5,480,587	$ 4,973,279	10.20%
44	401(k) Plan Defined Contribution Costs Capitalized	1,128,410	1,064,105	6.04%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,470	1,418	3.67%
48	Not Covered by the Plan			
49	Active - Participating	1,434	1,382	3.76%
50	Retired			
51	Vested Former Employees, Retirees and Active-	477	237	101.27%
52	Noncontributing			

2/ This plan covers all NorthWestern Corporation employees.

3/ Represents total company 401(k) plan participants.

Sch. 15	Other Post Employment Benefits (OPEBS)			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2009.9.129			
4	Order number: 7046h			
5	Amount recovered through rates	$177,804	$418,239	-57.49%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	3.75%	2.80%	33.93%
8	Expected return on plan assets	7.00%	7.00%	
9	Medical Cost Inflation Rate 3/	8.25%,4.5%:15	8.50%,4.5%:16	
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	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% 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				

1/ Obtained from NorthWestern Energy-Montana's 2013 FASB 106 Valuation. Assumptions and data are as of December 31, 2013.
2/ Obtained from NorthWestern Energy-Montana's 2012 FASB 106 Valuation. Assumptions and data are as of December 31, 2012.
3/ First Year, Ultimate, Years to Reach Ultimate.

Sch. 15a	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 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$23,181,823	$22,420,683	3.39%
10	Service cost	434,332	441,640	-1.65%
11	Interest Cost	616,759	817,698	-24.57%
12	Plan participants' contributions	775,242	957,107	-19.00%
13	Amendments	-	-	-
14	Actuarial loss/(gain)	(2,304,870)	998,382	>-300.00%
15	Acquisition	-	-	-
16	Benefits paid	(2,026,167)	(2,453,687)	17.42%
17	Benefit obligation at end of year	$20,677,119	$23,181,823	-10.80%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$15,893,406	$15,502,279	2.52%
20	Actual return on plan assets	2,661,840	1,789,246	48.77%
21	Acquisition	-	-	-
22	Employer contribution	878,874	98,461	>300.00%
23	Plan participants' contributions	775,242	957,107	-19.00%
24	Benefits paid	(2,026,167)	(2,453,687)	17.42%
25	Fair value of plan assets at end of year	$18,183,195	$15,893,406	14.41%
26	**Funded Status**	($2,493,924)	($7,288,417)	65.78%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	($2,493,924)	($7,288,417)	65.78%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	434,332.00	$441,640	-1.65%
33	Interest cost	616,759	817,698	-24.57%
34	Expected return on plan assets	(1,019,000)	(1,020,701)	0.17%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,148,915)	($2,148,915)	
37	Recognized net actuarial loss/(gain)	733,305	767,193	-4.42%
38	Net periodic benefit cost	($1,383,519)	($1,143,085)	-21.03%
39	**Accumulated Post Retirement Benefit Obligation**		-	
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	878,875	98,461	>300.00%
43	TOTAL	$878,875	$98,461	>300.00%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	177,804	418,239	-57.49%
47	TOTAL	$177,804	$418,239	-57.49%
48	**Montana Intrastate Costs:**			
49	Pension Costs	$177,804	$418,239	-57.49%
50	Pension Costs Capitalized	36,608	89,488	-59.09%
51	Accumulated Pension Asset (Liability) at Year End	(2,493,924)	(7,288,417)	65.78%
52	**Number of Montana Employees:**		-	
53	Covered by the Plan	1,971	2,011	-1.99%
54	Not Covered by the Plan	148	172	-13.95%
55	Active	926	971	-4.63%
56	Retired	950	933	1.82%
57	Spouses/Dependants covered by the Plan	95	107	-11.21%

4/ There is approximately an additional $9,406,969 and $10,858,097 in other company OPEBS liabilities outstanding at December 31, 2013 and 2012, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

SCHEDULE 16

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	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	227,684	86,745 A	42,758 B 88,627 C 2,539 D 875 E	449,228	428,715	5%
2	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	210,898	80,350 A	17,494 B 82,082 C	390,824	500,790	-22%
3	Michael R. Cashell Vice President, Transmission	194,728	74,189 A	29,389 B 75,783 C 5,307 D	379,396	491,284	-23%
4	John D. Hines Vice President, Supply	194,728	74,189 A	16,744 B 75,783 C 4,054 D 12,440 F	377,938	383,888	-2%
5	Michael L. Nieman Chief Audit and Compliance Officer	198,331	53,972 A	44,481 B 38,866 C	335,650	361,619	-7%
6	Daniel L. Rausch Treasurer	186,563	57,153 A	41,102 B 36,499 C 6,571 D	327,888	302,603	8%
7	Jeanne M. Barnett Vold Business Technology Officer	170,014	52,050 A	23,721 B 33,306 C 25,000 G 136 H	304,227	250,821	21%
8	John S. Fitzpatrick Executive Director, State/Local Community Relations	176,319	31,134 A	22,012 B 21,183 C 25,358 D 3,526 I	279,532	301,528	-7%
9	William T. Rhoads General Manager, Generation	172,184	37,954 A	22,839 B 26,982 C 5,589 D	265,549	364,620	-27%
10	John P. Kasperick Director, Financial Planning & Analysis	156,259	34,019 A	24,779 B 24,499 C 9,086 D	248,642	NA	

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2013 Annual Incentive Compensation Plan. Amounts were earned in 2013 and paid in the first quarter of 2014. Based on company performance against plan, the incentive plan was funded at 108% of target. Individual awards varied from the funded level based on individual performance.

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, Health Savings Account, wellness incentive, 401(k) match, and non-elective 401(k) contribution.

C> Values reflect the grant date fair value for performance stock awards.

D> Vacation sold back during the year.

E> Imputed income related to Hebgen facilities use.

F> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2013. The present value decreased for most participants as the result of significantly higher discount rates used to determine the actuarial present value of these benefits when compared to the prior year. No change in pension value is shown for these participants. Participants with an increase in pension value had a large enough percentage increase in the pension benefit to offset the impact of the higher discount rates.

G> Merit bonus.

H> Noncash taxable award and gross-up taxes on award.

I> Merit cash.

SCHEDULE 17

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	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Robert C. Rowe President & Chief Executive Officer	540,764	470,913 A	20,577 B 666,183 C 26,461 D	1,724,898	1,498,691	15%
2	Brian B. Bird Vice President & Chief Financial Officer	354,749	193,079 A	43,055 B 281,088 C	871,971	803,749	8%
3	Heather H. Grahame Vice President & General Counsel	322,815	140,558 A	44,903 B 184,382 C	692,658	628,357	10%
4	Curtis T. Pohl Vice President, Retail Operations	254,159	110,665 A	45,059 B 145,163 C 3,587 E	558,633	562,974	-1%
5	Kendall Kliewer Vice President & Controller	234,471	89,330 A	43,020 B 91,234 C	458,055	440,051	4%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2013 Annual Incentive Compensation Plan. Amounts were earned in 2013 and paid in the first quarter of 2014. Based on company performance against plan, the incentive plan was funded at 108% of target.

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, Health Savings Account, wellness incentive, 401(k) match, and non-elective 401(k) contribution.

C> Values reflect the grant date fair value for performance stock awards.

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2013. The present value decreased for most participants as the result of significantly higher discount rates used to determine the actuarial present value of these benefits when compared to the prior year. No change in pension value is shown for these participants. Participants with an increase in pension value had a large enough percentage increase in the pension benefit to offset the impact of the higher discount rates.

E> Vacation sold back during the year.

Sch. 18	BALANCE SHEET 1/				
	Account Title	This Year	Last Year	Variance	% Change
1	**Assets and Other Debits**				
2	**Utility Plant**				
3	101 Plant in Service	$3,974,701,127	$3,723,508,020	$251,193,107	6.75%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	-	0.00%
5	105 Plant Held for Future Use	3,560,555	4,900	3,555,655	>300.00%
6	107 Construction Work in Progress	97,044,707	115,303,982	($18,259,275)	-15.84%
7	108 Accumulated Depreciation Reserve	(1,616,152,234)	(1,557,915,890)	($58,236,344)	3.74%
8	108.1 Accumulated Depreciation - Capital Leases	(15,078,542)	(13,068,062)	($2,010,480)	15.38%
9	111 Accumulated Amortization & Depletion Reserves	(27,467,302)	(27,265,816)	($201,486)	0.74%
10	114 Electric Plant Acquisition Adjustments	-	-	-	-
11	115 Accumulated Amortization-Electric Plant Acq. Adj.		-	-	-
12	116 Utility Plant Adjustments	355,128,500	355,128,500	-	0.00%
13	117 Gas Stored Underground-Noncurrent	32,120,387	32,116,873	3,514	0.01%
14	**Total Utility Plant**	2,844,066,735	2,668,022,044	176,044,691	6.60%
15	**Other Property and Investments**				
16	121 Nonutility Property	6,749,606	9,971,371	(3,221,765)	-32.31%
17	122 Accumulated Depr. & Amort.-Nonutility Property	(819,346)	(625,930)	(193,416)	30.90%
18	123.1 Investments in Assoc Companies and Subsidiaries	(141,594,938)	(160,632,859)	19,037,921	-11.85%
19	124 Other Investments	16,784,220	10,956,526	5,827,694	53.19%
20	128 Miscellaneous Special Funds	-	-	-	-
21	LT Portion of Derivative Assets - Hedges	-	-	-	-
22	**Total Other Property & Investments**	(118,880,458)	(140,330,892)	21,450,434	-15.29%
23	**Current and Accrued Assets**				
24	131 Cash	10,387,435	9,783,614	603,821	6.17%
25	134 Other Special Deposits	4,169,290	2,920,144	1,249,146	42.78%
26	135 Working Funds	40,125	38,500	1,625	4.22%
27	136 Temporary Cash Investments	-	-	-	-
28	141 Notes Receivable	-	-	-	-
29	142 Customer Accounts Receivable	88,584,019	68,107,331	20,476,688	30.07%
30	143 Other Accounts Receivable	16,564,952	7,314,152	9,250,800	126.48%
31	144 Accumulated Provision for Uncollectible Accounts	(4,451,666)	(3,237,838)	(1,213,828)	37.49%
32	145 Notes Receivable-Associated Companies	-	-	-	-
33	146 Accounts Receivable-Associated Companies	148,135	2,043,636	(1,895,501)	-92.75%
34	151 Fuel Stock	8,460,264	8,385,009	75,255	0.90%
35	154 Plant Materials and Operating Supplies	26,791,073	25,514,876	1,276,197	5.00%
36	164 Gas Stored - Current	18,351,754	20,240,870	(1,889,116)	-9.33%
37	165 Prepayments	13,775,768	10,863,608	2,912,160	26.81%
38	171 Interest and Dividends Receivable	-	-	-	-
40	172 Rents Receivable	80,272	108,165	(27,893)	-25.79%
41	173 Accrued Utility Revenues	74,345,656	71,442,599	2,903,057	4.06%
42	174 Miscellaneous Current & Accrued Assets	877	164,316	(163,439)	-99.47%
43	175 Derivative Instrument Assets (175)	-	-	-	100.00%
44	(Less) Long-Term Portion of Derivative Instrument Assets	-	-	-	-
45	176 LT Portion of Derivative Assets - Hedges	-	-	-	-
46	(less) LT Portion of Derivative Assets - Hedges	-	-	-	-
47	**Total Current & Accrued Assets**	257,247,954	223,688,982	33,558,972	15.00%
48	**Deferred Debits**				
49	181 Unamortized Debt Expense	13,614,516	10,716,719	2,897,797	27.04%
50	182 Regulatory Assets	324,402,612	382,486,507	(58,083,895)	-15.19%
51	183 Preliminary Survey and Investigation Charges	1,185,617	1,162,190	23,427	2.02%
52	184 Clearing Accounts	30,449	12,306	18,143	147.43%
53	185 Temporary Facilities	-	-	-	-
54	186 Miscellaneous Deferred Debits	876,649	1,353,494	(476,845)	-35.23%
55	189 Unamortized Loss on Reacquired Debt	13,918,710	13,944,342	(25,632)	-0.18%
56	190 Accumulated Deferred Income Taxes	125,015,983	148,027,620	(23,011,637)	-15.55%
57	191 Unrecovered Purchased Gas Costs	16,260,432	6,285,942	9,974,490	158.68%
58	**Total Deferred Debits**	495,304,968	563,989,120	(68,684,152)	-12.18%
59	**TOTAL ASSETS and OTHER DEBITS**	$ 3,477,739,199	$ 3,315,369,254	$ 162,369,945	4.90%

Sch. 18	cont. BALANCE SHEET 1/				
	Account Title	This Year	This Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 423,405	$ 407,917	$ 15,488	3.80%
4	204 Preferred Stock Issued	-	-	-	-
5	207 Premium on Capital Stock	-	-	-	-
6	211 Miscellaneous Paid-In Capital	910,184,562	849,218,725	60,965,837	7.18%
7	213 Discount on Capital Stock	-	-	-	-
8	214 Capital Stock Expense	-	-	-	-
9	215 Appropriated Retained Earnings	-	-	-	-
10	216 Unappropriated Retained Earnings	209,090,660	172,791,546	36,299,114	21.01%
12	217 Reacquired Capital Stock	(91,744,257)	(90,702,563)	(1,041,694)	1.15%
13	219 Accumulated Other Comprehensive Income	2,716,002	2,316,682	399,320	17.24%
14	**Total Proprietary Capital**	1,030,670,372	934,032,307	96,638,065	10.35%
15	**Long Term Debt**				
16	221 Bonds	1,155,205,000	1,055,205,000	100,000,000	9.48%
17	223 Advances in Associated Companies	-	-	-	-
18	224 Other Long Term Debt	-	-	-	-
19	226 (Less) Unamortized Discount on Long Term Debt-Debit	107,538	131,638	(24,100)	-18.31%
20	**Total Long Term Debt**	1,155,097,462	1,055,073,362	100,024,100	9.48%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	29,894,898	31,562,420	(1,667,522)	-5.28%
23	228.1 Accumulated Provision for Property Insurance	-	-	-	-
24	228.2 Accumulated Provision for Injuries and Damages	8,748,808	11,081,906	(2,333,098)	-21.05%
25	228.3 Accumulated Provision for Pensions and Benefits	19,808,834	23,984,164	(4,175,330)	-17.41%
26	228.4 Accumulated Miscellaneous Operating Provisions	164,641,920	166,841,275	(2,199,355)	-1.32%
27	229 Accumulated Provision for Rate Refunds	27,235,028	24,618,109	2,616,919	10.63%
28	230 Asset Retirement Obligations	18,803,779	9,230,322	9,573,457	103.72%
29	**Total Other Noncurrent Liabilities**	269,133,267	267,318,196	1,815,071	0.68%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	140,949,554	122,933,903	18,015,651	14.65%
32	232 Accounts Payable	97,936,435	87,258,806	10,677,629	12.24%
33	233 Notes Payable to Associated Companies	-	-	-	-
34	234 Accounts Payable to Associated Companies	1,420,295	-	1,420,295	-
35	235 Customer Deposits	10,847,568	12,502,752	(1,655,184)	-13.24%
36	236 Taxes Accrued	41,116,000	32,161,732	8,954,268	27.84%
37	237 Interest Accrued	18,038,039	17,876,133	161,906	0.91%
39	238 Dividends Declared	-	-	-	-
40	241 Tax Collections Payable	1,467,454	1,167,397	300,057	25.70%
41	242 Miscellaneous Current and Accrued Liabilities	57,359,785	56,059,420	1,300,365	2.32%
42	243 Obligations Under Capital Leases-Current	1,662,235	1,611,617	50,618	3.14%
43	244 Derivative Instrument Liabilities	-	5,428,321	(5,428,321)	-100.00%
44	245 Derivative Instrument Liabilities - Hedges	-	-	-	-
45	**Total Current and Accrued Liabilities**	370,797,365	337,000,081	33,797,284	10.03%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	27,370,414	34,680,992	(7,310,578)	-21.08%
48	253 Other Deferred Credits	94,739,483	176,005,656	(81,266,173)	-46.17%
49	254 Regulatory Liabilities	22,852,872	27,572,155	(4,719,283)	-17.12%
50	255 Accumulated Deferred Investment Tax Credits	861,860	1,196,810	(334,950)	-27.99%
51	257 Unamortized Gain on Reacquired Debt	-	-	-	-
52	281-283 Accumulated Deferred Income Taxes	506,216,103	482,489,695	23,726,408	4.92%
53	**Total Deferred Credits**	652,040,732	721,945,308	(69,904,576)	-9.68%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 3,477,739,198	$ 3,315,369,254	$ 162,369,944	4.90%
55					

56 1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory
57 Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the
58 equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian
59 Montana Pipeline Corp.

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NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 678,200 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed 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 the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. The preparation of financial statements in conformity with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases 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. Events occurring subsequent to December 31, 2013, have been evaluated as to their potential impact to the Financial Statements through the date of issuance.

(2) Significant Accounting Policies

Financial Statement Presentation

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 and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Accounting Standards Codification (ASC) 810 "Consolidation". ASC 810 requires that all majority-owned subsidiaries be consolidated (see Note 5). The other significant differences consist of the following:

- Earnings per share is not presented;
- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $336.6 million and $264.5 million as of December 31, 2013 and December 31, 2012, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes (see Note 8);
- Goodwill is reflected in the Balance Sheets as a utility plant adjustment of $355.1 million as of December 31, 2013 and December 31, 2012, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 9);
- 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 $147.6 million for December 31, 2013 and December 31, 2012, 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 inventory 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 current and long-term debt are separately presented for GAAP reporting;

- Accumulated deferred tax assets and liabilities are classified in the Balance Sheets as gross non-current deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred tax asset or liability separately classified as current or non-current; and

- Regulatory assets and liabilities are reflected in the Balance Sheets as non-current items, while current and non-current amounts are separately presented for GAAP.

Use of Estimates

The preparation of financial statements in conformity with the regulatory basis of accounting 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, asset retirement obligations, uncollectible accounts, our QF liability, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

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 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.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $4.5 million and $3.2 million at December 31, 2013 and December 31, 2012, respectively. Unbilled revenues were $74.3 million and $71.4 million at December 31, 2013 and December 31, 2012, respectively.

Inventories

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

	December 31, 2013	December 31, 2012
Fuel stock	$ 8,460	$ 8,385
Materials and supplies	26,791	25,515
Gas stored underground (including the non-current portion reflected in utility plant)	50,472	52,358
	$ 85,723	$ 86,258

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980, *Regulated Operations* (ASC 980). Regulated accounting 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 jurisdictions 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 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 we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Statement of Income at that time. This would result in a charge to earnings, net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, *Derivatives and Hedging*. All derivatives are recognized in the Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated other comprehensive income (AOCI) and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Statements of Cash Flows, depending on the underlying nature of the hedged items.

Revenues and expenses on contracts that qualify are designated as normal purchases and normal sales and are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 10, Risk Management and Hedging Activities for further discussion of our derivative activity.

Utility Plant

Utility plant is 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 plant 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 utility plant are assets under capital lease, which are stated at the present value of minimum lease payments.

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 net interest charges, 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 8.1% and 8.0% for Montana and South Dakota for 2013 and 2012, respectively. AFUDC capitalized totaled $8.2 million for the year ended December 31, 2013 and $7.9 million for the year ended December 31, 2012 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 $6.3 million and $5.0 million for the years ended December 31, 2013 and 2012, 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 40 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 3.2% and 3.3% for 2013 and 2012, respectively. During the second quarter of 2013, we implemented revised depreciation rates to reflect the results of new depreciation studies, which reflect longer asset lives on our electric and natural gas assets in Montana, and electric assets in South Dakota.

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, while the accumulated provisions are included in accumulated depreciation.

Income Taxes

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 Statements of Income 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 there is precedent for recovering similar costs from customers in rates. Otherwise, we expense the costs. If an environmental cost is related to facilities we currently use, such as pollution control equipment, then we may capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, 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.

Accounting Standards Issued

In July 2013, the Financial Accounting Standards Board (FASB) issued guidance for the presentation of unrecognized tax benefits when a net operating loss carryforward or other tax credit carryforwards exist at the reporting date. If such a carryforward exists, the guidance generally requires an unrecognized tax benefit to be presented as a decrease in a deferred tax asset. Our current practice is consistent with this guidance.

Accounting Standards Adopted

In February 2013, the FASB issued guidance that requires disclosure of amounts reclassified out of AOCI by component. Significant amounts are required to be presented by the respective line items of net income or should be cross-referenced to other disclosures. These disclosures may be presented on the income statement or in the notes to the financial statements. We adopted this standard during the first quarter of 2013 and have included the required disclosures in Note 16 – Other Comprehensive Income (Loss). The adoption of this standard did not have a material effect on our financial statement disclosures.

(3) Acquisitions and Significant Events

Hydro Transaction

On September 26, 2013, we entered into an agreement with PPL Montana, LLC (PPL Montana), a wholly owned subsidiary of PPL Corporation, to purchase PPL Montana's hydro-electric generating facilities and associated assets located in Montana, which includes approximately 633 megawatts of hydro-electric generation capacity, for a purchase price of $900 million (Hydro Transaction). The purchase price will be subject to a number of adjustments, including the proration of operating expenses, the performance of planned capital expenditures, and the termination of certain power purchase agreements.

The Hydro Transaction includes the Kerr Project, a 194 megawatt hydro-electric generating facility. The FERC license for the Kerr Project provides the Confederated Salish and Kootenai Tribes of the Flathead Reservation (CSKT) an option to acquire the facility between September 2015 and September 2025. We believe CSKT will exercise their option and acquire the Kerr Project in September 2015. PPL Montana and CSKT are currently involved in arbitration over the conveyance price of the Kerr Project. Under our agreement with PPL Montana, the $900 million purchase price includes a $30 million reference price to the Kerr Project. If CSKT exercises their option and ultimately pays more than $30 million for the Kerr Project, we will pay the difference to PPL Montana. If CSKT pays less than $30 million for the Kerr Project, PPL Montana will pay the difference to us.

Completion of the Hydro Transaction is subject to customary conditions and approvals, including approval from the FERC, the Montana Public Service Commission (MPSC), other appropriate state and federal agencies and as required by the Hart-Scott-Rodino Antitrust Improvements Act. In December 2013, we submitted an application with the MPSC to acquire these assets, and in January 2014, we submitted three applications with the FERC concerning the Hydro Transaction. For further information on these filings see Note 4 - Regulatory Matters. Either party may terminate the agreement if the closing does not occur by September 26, 2014; however, this date will be extended for an additional six months if any governmental approval is still pending. Assuming receipt of satisfactory regulatory approvals, we expect the Hydro Transaction to close in the second half of 2014.

The permanent financing for the Hydro Transaction is anticipated to be a combination of long-term debt, new equity issuance and cash flows from operations. The Hydro Transaction is supported by a fully committed $900 million 364-day senior bridge credit facility (see Note 12 - Notes Payable and Credit Arrangements).

During 2013, we incurred approximately $4.4 million of legal and professional fees associated with the Hydro Transaction and approximately $1.9 million of expenses related to the bridge credit facility.

If the acquisition is completed during the second half of 2014, we expect to sell any excess generation in the market and provide revenue credits to our Montana retail customers until CSKT exercises their option to acquire the Kerr Project. If CSKT exercises their option to acquire the Kerr Project in September 2015, we will own approximately 60 percent of our average electric load serving requirements in Montana.

Natural Gas Production Assets

In December 2013, we completed the purchase of additional natural gas production interests in northern Montana's Bear Paw Basin for approximately $68.7 million net of cash acquired, subject to post-closing purchase price adjustments. This purchase includes an interest in the Havre Pipeline Company, LLC (Havre Pipeline), which represents approximately $6 million of pipeline assets. As of December 31, 2013, the amount of net proven developed producing reserves associated with the acquisition was estimated to be 57.5 billion cubic feet. We estimate the current annual production associated with this acquisition to be approximately 24 percent of our total annual natural gas load in Montana, which increases our total owned production to approximately 32 percent.

Colstrip Energy Limited Partnership (CELP)

CELP is a QF with which we have a power purchase agreement (PPA) for approximately 306,600 MWH's annually through June 2024. Under the terms of the PPA with CELP, energy and capacity rates were fixed for the first fifteen years and beginning July 1, 2004, through the end of the contract, energy and capacity rates are to be determined each year pursuant to a formula, subject to annual review and approval by the MPSC. CELP filed a complaint against us and the MPSC in Montana district court in 2007, which contested the MPSC's orders.

On November 1, 2012, an arbitration panel issued a final award in our favor. The final award confirmed that the rate methodology used by us for calculating the rates for the July 1, 2006 to July 1, 2011 period was consistent with the PPA and a previous final award issued by the same arbitration panel on October 30, 2009. Based on the clarity provided by the final award regarding the rate calculation for 2006 through the remainder of the PPA, we updated the calculation of our QF liability and recorded a pre-tax gain of $47.9 million within operation expenses in the Statements of Income during the fourth quarter of 2012. In April 2013, the MPSC issued a final order consistent with the arbitration panel's final award for the contract years July 1, 2006 through June 30, 2013.

(4) Regulatory Matters

Hydro Transaction

In December 2013, we submitted a filing with the MPSC requesting approval of the Hydro Transaction. The filing initiates the formal regulatory process necessary to complete the previously announced $900 million agreement, and includes a request to include the hydro assets in rate base and to issue the securities necessary to complete the purchase. The request is based on a return on equity of 10%, a capital structure of 52% debt and 48% equity, and an estimated first year average rate base of $866 million. Based on the MPSC's procedural schedule, we expect the MPSC to issue a decision during the second half of 2014.

In January 2014, we made three separate applications with the FERC necessary for the Hydro Transaction seeking (1) approval of the asset transfer itself, (2) authorization to continue making wholesale power sales at market-based rates after the transaction and (3) approval to transfer the four associated FERC hydroelectric licenses. We anticipate that FERC will act before June 30, 2014, the requested action date for the first two applications. The CSKT protested the third application to transfer the FERC hydro licenses and asked FERC to reject the application with respect to the Kerr Project. As noted above, in March 2014, FERC approved the transfer of three of the licenses and indicated they would process the transfer of the license for the Kerr Project in a separate proceeding. We are currently working with PPL Montana and the CSKT to address the CSKT concerns with respect to the license transfer for the Kerr Project.

Dave Gates Generating Station at Mill Creek (DGGS)

As a result of a FERC Administrative Law Judge (ALJ) nonbinding decision issued in September 2012, we have cumulative deferred revenue of approximately $27.0 million, which is subject to refund and recorded within current regulatory liabilities in the Condensed Consolidated Balance Sheets. The ALJ concluded we should allocate only a fraction of the costs we believe (based on past practice) should be allocated to FERC jurisdictional customers.

The matter was fully briefed before the FERC and on April 17, 2014, the FERC issued an order affirming the ALJ's decision. The order requires us to issue customer refunds (included in deferred revenue discussed above) within 30 days. We are reviewing the decision, and may pursue full appellate rights through rehearing to the FERC. If unsuccessful on rehearing, we may appeal to a United States Circuit Court of Appeals, which could extend into 2016 or beyond. Based on the FERC decision, we assessed this triggering event and whether an impairment charge should be recorded with respect to DGGS. We are evaluating options to use DGGS in combination with other generation resources to ensure full cost recovery, and therefore do not currently believe an impairment loss is probable. However, any alternative use of DGGS would be subject to regulatory approval and we cannot provide assurance of such approval. We will continue to evaluate recovery of this asset in the future as facts and circumstances change.

Montana Electric and Natural Gas Tracker Filings

Each year we submit electric and natural gas tracker filings for recovery of supply costs for the 12-month period ended June 30 and for the projected supply costs for the next 12-month period. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our electric and natural gas supply procurement activities were prudent.

During October 2013, the MPSC approved an order related to our 2012 electric supply tracker filing (covering July 1, 2011 through June 30, 2012), which included a decision on a review of an independent study related to our request for demand-side management (DSM) lost revenues and addresses future DSM lost revenue recovery. The order also includes a provision expressing concern with the policy of continuing to allow DSM lost revenue recovery, indicating that we bear the burden of demonstrating why any incremental DSM lost revenue recovery from the date of its October 2013 order forward is reasonable and in the public interest. We appealed the MPSC's order to District Court in Montana and we are currently in settlement discussions with MPSC staff related to DSM lost revenue recovery.

Based on the MPSC's order, we expect to be able to collect at least $7.1 million of DSM lost revenues for each annual tracker period; however, since the 2012/2013 annual tracker filing is still subject to final approval, the MPSC may ultimately require us to refund a portion of the DSM lost revenues we have recognized since July 2012. We do not expect the MPSC to issue a final order related to 2012/2013 electric tracker until at least the second half of 2014.

Natural Gas Production Assets

In 2012 and 2013, we purchased natural gas production interests in northern Montana's Bear Paw Basin (Bear Paw). We are collecting the cost of service for natural gas produced from these assets, including a return on our investment, through our natural gas supply tracker on an interim basis. As a result, we do not expect to file an application with the MPSC to place these assets in natural gas rate base until our next natural gas rate case. We are recognizing Bear Paw related revenue based on the precedent established by the MPSC's approval of Battle Creek in the fourth quarter of 2012. Since acquisition, we have recognized approximately $16.7 million of revenue that is subject to refund.

(5) Equity Investments

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

	December 31, 2013	December 31, 2012
Colstrip Unit 4 Basis Adjustment	$ (159,895)	$ (162,848)
Havre Pipeline Company, LLC	14,576	-
Mountain States Transmission Intertie, LLC	-	9,379
NorthWestern Services, LLC	1,876	(9,926)
Risk Partners Assurance, Ltd.	1,848	2,762
Total Investments in Subsidiary Companies	$ (141,595)	$ (160,633)

(6) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, 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. These 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 97% of our regulatory assets and 100% of our regulatory liabilities.

	Note Reference	Remaining Amortization Period	December 31, 2013	December 31, 2012
			(in thousands)	
Pension	18	Undetermined	$ 58,474	$ 143,672
Employee related benefits	18	Undetermined	17,700	20,911
Distribution infrastructure projects		4 Years	12,543	15,679
Environmental clean-up	21	Various	14,924	16,497
Energy supply derivatives	10	1 Year	--	5,428
Income taxes	15	Plant Lives	201,808	162,154
State & local taxes & fees		1 Year	6,582	8,337
Other		Various	12,372	9,809
Total regulatory assets			**$ 324,403**	**$ 382,487**
Gas storage sales		26 Years	$ 10,831	$ 11,251
Unbilled revenue		1 Year	9,868	12,030
Environmental clean-up		Various	1,226	1,482
State & local taxes & fees		1 Year	551	537
Other		Various	377	2,272
Total regulatory liabilities			**$ 22,853**	**$ 27,572**

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The South Dakota Public Utilities Commission (SDPUC) allows recovery of pension costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis. The MPSC allows recovery of other employee related benefits on a cash basis.

Montana Distribution System Infrastructure Project (DSIP)

We have an accounting order to defer certain incremental operating and maintenance expenses associated with DSIP. Pursuant to the order, we deferred expenses incurred during 2011 and 2012 as a regulatory asset associated with the phase-in portion of the DSIP. These costs are being amortized into expense over five years beginning in 2013.

Energy Supply Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts. Certain contracts for the purchase of natural gas associated with our gas utility operations do not qualify for the normal purchase and normal sale scope exception (NPNS). We use the mark-to-market method of accounting for these derivative contracts as we do not elect hedge accounting. Upon settlement of these contracts, associated proceeds or costs are refunded to or collected from our customers consistent with regulatory requirements; therefore, we record a regulatory asset or liability based on changes in market value.

Environmental clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 21 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. We record changes in the regulatory asset consistent with changes in our environmental liabilities. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Income Taxes

Tax assets primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and recover these amounts. The MPSC has authorized recovery in the property tax tracker of approximately 60% of the estimated increase in our local taxes and fees (primarily property taxes) as compared to the related amount included in rates during our last general rate case.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion 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.

Unbilled Revenue

In accordance with regulatory guidance in South Dakota, we recognize revenue when it is billed. Accordingly, we record a regulatory liability to offset unbilled revenue.

(7) Utility Plant

The following table presents the major classifications of our net utility plant (in thousands):

	December 31, 2013	December 31, 2012
Land and improvements	$ 128,886	$ 73,370
Building and improvements	236,668	220,607
Storage, distribution, and transmission	2,641,325	2,502,640
Generation	757,698	728,252
Construction work in process	97,045	115,304
Other equipment	253,891	238,853
	4,115,516	3,879,026
Less accumulated depreciation	(1,658,698)	(1,598,250)
	$ 2,456,818	$ 2,280,776

Plant and equipment under capital lease were $25.6 million and $27.7 million as of December 31, 2013 and 2012, respectively, which included $25.1 million and $27.1 million as of December 31, 2013 and 2012, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as an obligation under capital lease.

Jointly Owned Electric Generating Plant

We have an ownership interest in four base-load electric generating plants, all of which are coal fired and operated by other 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. The participants each finance their own investment.

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

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2013				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 61,186	$ 57,633	$ 46,003	$ 290,163
Accumulated depreciation	45,792	29,841	36,076	70,072
December 31, 2012				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 61,084	$ 30,009	$ 46,188	$ 290,607
Accumulated depreciation	38,021	23,994	30,655	67,534

(8) Asset Retirement Obligations

We are obligated to dispose of certain long-lived assets upon their abandonment. We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our property, plant and equipment and other noncurrent liabilities. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligation (ARO) is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated ARO can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

Our AROs are primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, and our obligation to plug and abandon oil and gas wells at the end of their life. The following table presents the change in our gross conditional ARO (in thousands):

	December 31, 2013	December 31, 2012
Liability at January 1,	$ 9,283	$ 6,292
Accretion expense	745	473
Liabilities incurred	8,829	2,466
Liabilities settled	(27)	(35)
Revisions to cash flows	2,056	87
Liability at December 31,	$ 20,886	$ 9,283

Liabilities incurred includes amounts related to the natural gas production assets acquired.

Our regulated utility operations have previously recognized removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. These amounts do not represent legal retirement obligations. As of December 31, 2013 and 2012, we have recognized accrued removal costs of $336.6 million and $264.5 million, respectively, which are classified as accumulated depreciation.

We have identified removal 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.

(9) Utility Plant Adjustments

We completed our annual utility plant adjustments impairment test as of April 1, 2013 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

(10) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a large portion of our electric and natural gas supply requirements within the Montana market. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts, such as fixed-price forward purchase and sales contracts. The objective of these transactions is to fix the price for a portion of anticipated energy purchases to supply our customers. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide greater price stability for consumers. These commodity costs are included in our cost tracking mechanisms and are recoverable from customers subject to prudence reviews by the applicable state regulatory commissions. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes consistent with regulatory guidelines. In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale; cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. 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.

Normal Purchases and Normal Sales

We have applied the NPNS exception to most of our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no amounts recorded in the Financial Statements at December 31, 2013 and 2012. 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.

Mark-to-Market Accounting

Certain contracts for the purchase of natural gas associated with our gas utility operations do not qualify for NPNS. These are typically forward purchase contracts for natural gas where we lock in a fixed price, settle the contracts financially and do not take physical delivery of the natural gas. We use the mark-to-market method of accounting for these derivative contracts as we do not elect hedge accounting. Upon settlement of these contracts, associated proceeds or costs are refunded to or collected from our customers consistent with regulatory requirements; therefore, we record a regulatory asset or liability based on changes in market value.

The following table represents the fair value and location of derivative instruments subject to mark-to-market accounting (in thousands). For more information on the determination of fair value see Note 11 - Fair Value Measurements.

Mark-to-Market Transactions	Balance Sheet Location	December 31, 2013	December 31, 2012
Natural gas net derivative liability	Current and Accrued Liabilities	$ —	$ 5,428

The following table represents the net change in fair value for these derivatives (in thousands):

Derivatives Subject to Regulatory Deferral	Unrealized gain recognized in Regulatory Assets December 31, 2013	Unrealized gain recognized in Regulatory Assets December 31, 2012
Natural gas	$ 5,428	$ 14,884

Credit Risk

We are exposed to credit risk primarily through buying and selling electricity and natural gas to serve customers. Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties.

We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements - standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements - standardized financial gas and electric contracts; (3) North American Energy

Standards Board agreements - standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements - standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

As of December 31, 2013, none of the forward purchase contracts that do not qualify for NPNS contain credit risk-related contingent features.

Interest Rate Swaps Designated as Cash Flow Hedges

If we enter into contracts to hedge 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 previously used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. These swaps were designated as cash flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCI. We reclassify these gains from AOCI into interest on long-term debt during the periods in which the hedged interest payments occur. The following table shows the effect of these derivative instruments on the Financial Statements (in thousands):

Cash Flow Hedges	Location of Gain Reclassified from AOCI to Income	Amount of Gain Reclassified from AOCI into Income during the Year Ended December 31, 2013
Interest rate contracts	Interest on long-term debt	$ 1,188

Approximately $5.7 million of the pre-tax gain on these cash flow hedges is remaining in AOCI as of December 31, 2013, and we expect to reclassify approximately $1.2 million of pre-tax gains on these cash-flow hedges from AOCI into interest expense during the next twelve months. These gains relate to swaps previously terminated, and we have no current interest rate swaps outstanding.

(11) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

A fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs has been established by the applicable accounting guidance. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;

- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. Normal purchases and sales transactions are not included in the fair values by source table as they are not recorded at fair value. See Note 10 - Risk Management and Hedging Activities for further discussion.

We record transfers between levels of the fair value hierarchy, if necessary, at the end of the reporting period. There were no transfers between levels for the periods presented.

December 31, 2013	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Other special deposits	$ 4,169	$ —	$ —	$ —	$ 4,169
Rabbi trust investments	16,477	—	—	—	16,477
Total	$ 20,646	$ —	$ —	$ —	$ 20,646
December 31, 2012					
Other special deposits	$ 2,920	$ —	$ —	$ —	$ 2,920
Rabbi trust investments	10,522	—	—	—	10,522
Derivative liability (1)	—	(5,428)	—	—	(5,428)
Total	$ 13,442	$ (5,428)	$ —	$ —	$ 8,014

(1) The changes in the fair value of these derivatives are deferred as a regulatory asset or liability until the contracts are settled. Upon settlement, associated proceeds or costs are passed through the applicable cost tracking mechanism to customers.

Other special deposits represent amounts held in money market mutual funds. Rabbi trust assets represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets. Fair value for the commodity derivatives was determined using internal models based on quoted forward commodity prices. We consider nonperformance risk in our valuation of derivative instruments by analyzing the credit standing of our counterparties and considering any counterparty credit enhancements (e.g., collateral). The fair value measurement of liabilities also reflects the nonperformance risk of the reporting entity, as applicable. Therefore, we have factored the impact of our credit standing as well as any potential credit enhancements into the fair value measurement of both derivative assets and derivative liabilities. Consideration of our own credit risk did not have a material impact on our fair value measurements.

The table above disaggregates our derivative liability on a gross contract-by-contract basis as required and classifies each individual liability within the appropriate level in the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts. These gross balances are intended solely to provide information on sources of inputs to fair value and do not represent our actual credit exposure or net economic exposure. Increases and decreases in the gross components presented in each of the levels in this table also do not indicate changes in the level of derivative activities. Rather, the primary factors affecting the gross amounts are commodity prices.

Financial Instruments

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

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 1,155,097	$ 1,237,151	$ 1,055,074	$ 1,229,233

Notes payable consist of commercial paper and are not included in the table above as carrying value approximates fair value. The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is 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.

We determined fair value for long-term debt 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, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

(12) Notes Payable and Credit Arrangements

Notes Payable

Notes payable and the corresponding weighted average interest rates as of December 31 were as follows (dollars in millions, except for percentages):

	2013		2012	
Notes Payable	Balance	Interest Rate	Balance	Interest Rate
Commercial Paper	$ 141.0	0.41%	$ 122.9	0.53%

The following information relates to commercial paper for the years ended December 31 (dollars in millions):

	2013	2012
Maximum short-term debt outstanding	$ 199.9	$ 166.9
Average short-term debt outstanding	$ 69.0	$ 78.9
Weighted-average interest rate	0.40%	0.48%

Under our commercial paper program we may issue unsecured commercial paper notes on a private placement basis up to a maximum aggregate amount outstanding at any time of $250 million to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Commercial paper issuances are supported by available capacity under our unsecured revolving credit facility.

Unsecured Revolving Line of Credit

On November 5, 2013, we amended and restated our $300 million unsecured revolving credit facility scheduled to expire on June 30, 2016, to extend the term to November 5, 2018. The facility has an accordion feature that allows us to increase the size up to $350 million. The facility does not amortize. The facility bears interest at the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%, or a base rate, plus a margin of 0.0% to 0.75%. A total of eight banks participate in the facility, with no one bank providing more than 16% of the total availability. There were no direct borrowings or letters of credit outstanding as of December 31, 2013. Commitment fees for the unsecured revolving line of credit were $0.5 million for the years ended December 31, 2013 and 2012.

The credit facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the credit facility; however a default on the credit facility would not trigger a default on any other obligations.

Bridge Facility

In November 2013, in connection with the Hydro Transaction, we entered into a $900 million 364-day senior bridge credit facility. The bridge facility may be used temporarily in a single draw to finance the Hydro Transaction and pay related fees and expenses in the event that permanent financing is not in place at the time of closing. Any advance under the bridge facility is subject to certain conditions including regulatory approval of the Hydro Transaction, and would be due and payable within one year of borrowing.

The bridge facility does not amortize and is unsecured. The bridge facility, if drawn, bears interest at the Eurodollar rate, plus a margin of 0.88% to 1.75%, or a base rate, plus a margin of 0.0% to 0.75%. The applicable margin would be determined based on our then-current senior unsecured credit ratings. If our current unsecured credit ratings are unchanged at the time of closing, the applicable margin would be 1.25% for Eurodollar rate loans and 0.25% for base rate loans. There were no direct borrowings or letters of credit outstanding as of December 31, 2013. Commitment fees for the bridge facility were $0.2 million for the year ended December 31, 2013.

The covenants in the bridge facility are substantially similar to those in our unsecured revolving line of credit. As of December 31, 2013, we are in compliance with our financial debt covenants.

(13) Long-Term Debt

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

	Due	December 31, 2013	December 31, 2012
Unsecured Debt:			
Unsecured Revolving Line of Credit	2018	$ —	$ —
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	55,000	55,000
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	—
Montana—6.04%	2016	150,000	150,000
Montana—6.34%	2019	250,000	250,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	—
Montana—3.99%	2028	35,000	—
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
Other Long Term Debt:			
Discount on Notes and Bonds	—	(108)	(131)
		$ 1,155,097	$ 1,055,074

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota Mortgage Bonds are a series of general obligation bonds issued 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 and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

In December 2013, we issued $65 million aggregate principal amount of Montana and South Dakota First Mortgage Bonds at a fixed interest rate of 4.85% maturing in 2043. At the same time, we also issued $35 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 3.99% maturing in 2028. The bonds are secured by our electric and natural gas assets in the respective jurisdictions. The bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. Proceeds were used to fund a portion of our investment growth opportunities.

As of December 31, 2013, we are in compliance with our financial debt covenants.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term during the next five years are zero in 2014 and 2015, $150.0 million in 2016, zero in 2017 and $55.0 million in 2018.

(14) 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, 2013	December 31, 2012
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 130	$ -
NorthWestern Services, LLC	-	2,026
Risk Partners Assurance, Ltd.	18	18
	$ 148	$ 2,044
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	$ 1,420	$ -

(15) Income Taxes

Our effective tax rate differs from the federal statutory tax rate of 35% primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions, state tax benefit of bonus depreciation deductions and production tax credits. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues, we record deferred income taxes and establish related regulatory assets and liabilities.

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 and electric costs which are deferred for book purposes but expensed currently for tax purposes, and NOL carry forwards. 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.

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

	December 31,	
	2013	2012
Pension / postretirement benefits	$ 20,522	$ 59,098
Unbilled revenue	18,136	15,942
NOL carryforward	16,758	—
Reserves and accruals	12,097	3,202
Customer advances	10,781	13,660
Compensation accruals	10,409	11,303
AMT credit carryforward	10,357	10,588
Environmental liability	9,026	9,701
Regulatory assets	7,248	—
Production tax credit	3,171	—
QF obligations	2,066	1,462
Property taxes	794	18,023
Regulatory liabilities	659	1,526
Other, net	2,992	3,523
Deferred Tax Asset	**125,016**	**148,028**
Excess tax depreciation	(304,402)	(276,453)
Goodwill amortization	(122,798)	(118,313)
Flow through depreciation	(79,016)	(63,551)
Regulatory assets	—	(24,173)
Deferred Tax Liability	**(506,216)**	**(482,490)**
Deferred Tax Liability, net	**$ (381,200)**	**$ (334,462)**

At December 31, 2013 we estimate our total federal NOL carryforward to be approximately $325.7 million. If unused, our federal NOL carryforwards will expire as follows: $16.3 million in 2025; $95.5 million in 2028; $23.8 million in 2029; $127.5 million in 2031; and $62.6 million in 2033. We estimate our state NOL carryforward as of December 31, 2013 is approximately $243.5 million. If unused, our state NOL carryforwards will expire as follows: $74.0 million in 2015; $18.6 million in 2016; $101.2 million in 2018; and $49.7 million in 2020. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (in thousands)

	2013	2012
Unrecognized Tax Benefits at January 1	$ 113,291	$ 131,949
Gross increases - tax positions in prior period	—	—
Gross decreases - tax positions in prior period	—	(1,766)
Gross increases - tax positions in current period	518	2,391
Gross decreases - tax positions in current period	(343)	(19,283)
Unrecognized Tax Benefits at December 31	$ 113,466	$ 113,291

Our unrecognized tax benefits include approximately $79.0 million related to tax positions as of each of December 31, 2013 and 2012 that, if recognized, would impact our annual effective tax rate. It is reasonably possible that a significant portion of our unrecognized tax benefits may decrease in the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the year ended December 31, 2013, we recognized approximately $0.4 million of interest in the Statements of Income. As of December 31, 2013, we have $0.4 million of interest accrued in the Balance Sheets. During the year ended December 31, 2012, we did not recognize any expense for interest or penalties, and did not have any amounts accrued as of December 31, 2012, for the payment of interest and penalties.

In September 2013, the IRS issued final tangible property regulations, which includes final guidance on a safe harbor method for determining the tax treatment of repair costs related to electric transmission and distribution property. The regulations are not effective until tax years beginning on or after January 1, 2014; however, certain portions require a tax accounting method change on a retroactive basis, thus requiring an adjustment related to fixed and real asset deferred taxes. Based on our preliminary analysis of the tangible property regulations, no material adjustments were recorded during 2013. We will continue to monitor the impact of any future changes to the tangible property regulations on our tax positions prospectively.

Our federal tax returns from 2000 forward remain subject to examination by the IRS.

(16) Other Comprehensive Income (Loss)

The following tables display the components of Other Comprehensive Income (Loss), after-tax, and the related tax effects (in thousands):

	December 31,					
	2013			2012		
	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount
Foreign currency translation adjustment	$ 166	$ —	$ 166	$ (54)	—	$ (54)
Reclassification of net gains on derivative instruments to net income	(1,188)	458	(730)	(1,188)	456	(732)
Reclassification of deferred tax liability on net gains on derivative instruments	—	—	—	—	—	—
Pension and postretirement medical liability adjustment	1,568	(605)	963	(897)	344	(553)
Other comprehensive income (loss)	$ 546	$ (147)	$ 399	$ (2,139)	$ 800	$ (1,339)

Balances by classification included within AOCI on the Balance Sheets are as follows, net of tax (in thousands):

	December 31, 2013	December 31, 2012
Foreign currency translation	$ 532	$ 366
Derivative instruments designated as cash flow hedges	3,513	4,243
Pension and postretirement medical plans	(1,329)	(2,292)
Accumulated other comprehensive income	2,716	2,317

The following table displays the changes in AOCI by component, net of tax (in thousands):

	Affected Line Item in the Statements of Income	December 31, 2013 Twelve Months Ended Gains on Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ 4,243	$ (2,292)	$ 366	$ 2,317
Other comprehensive income before reclassifications		—	—	166	$ 166
Amounts reclassified from accumulated other comprehensive income	Interest on long-term debt	(730)	—	—	$ (730)
Amounts reclassified from accumulated other comprehensive income		—	963	—	$ 963
Net current-period other comprehensive (loss) income		(730)	963	166	399
Ending balance		$ 3,513	$ (1,329)	$ 532	$ 2,716

(17) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2013 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2014	1,655
2015	1,260
2016	796
2017	434
2018	40

Lease and rental expense incurred was $2.0 million and $2.2 million for the years ended December 31, 2013 and 2012, respectively.

(18) 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 eligible 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. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our financial statements. See Note 6 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation and Funded Status

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2013	2012	2013	2012
Change in Benefit Obligation:				
Obligation at beginning of period	$ 609,643	$ 536,536	$ 34,040	$ 32,427
Service cost	13,465	11,488	541	541
Interest cost	22,719	23,823	877	1,167
Actuarial (gain) loss	(54,671)	59,071	(3,156)	2,508
Benefits paid	(23,290)	(21,275)	(2,218)	(2,603)
Benefit obligation at end of period	$ 567,866	$ 609,643	$ 30,084	$ 34,040
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 472,936	$ 432,637	$ 15,893	$ 15,502
Return on plan assets	55,006	49,874	2,662	1,789
Employer contributions	11,700	11,700	1,846	1,205
Benefits paid	(23,290)	(21,275)	(2,218)	(2,603)
Fair value of plan assets at end of period	$ 516,352	$ 472,936	$ 18,183	$ 15,893
Funded Status	$ (51,514)	$ (136,707)	$ (11,901)	$ (18,147)
Amounts recognized in the balance sheet consist of:				
Current liability	—	—	(1,178)	(1,082)
Noncurrent liability	(51,514)	(136,707)	(10,723)	(17,065)
Net amount recognized	$ (51,514)	$ (136,707)	$ (11,901)	$ (18,147)
Amounts recognized in regulatory assets consist of:				
Prior service (cost) credit	(748)	(994)	19,247	21,396
Net actuarial loss	(71,777)	(160,610)	(4,807)	(9,488)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(1,302)	(1,453)
Net actuarial gain	—	—	(971)	(2,432)
Total	$ (72,525)	$ (161,604)	$ 12,167	$ 8,023

The total projected benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were as follows (in millions):

	Pension Benefits	
	December 31,	
	2013	2012
Projected benefit obligation	$ 567.9	$ 609.6
Accumulated benefit obligation	565.0	606.2
Fair value of plan assets	516.4	472.9

Net Periodic Cost (Credit)

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2013	2012	2013	2012
Components of Net Periodic Benefit Cost				
Service cost	$ 13,465	$ 11,488	$ 541	$ 541
Interest cost	22,719	23,823	877	1,167
Expected return on plan assets	(32,491)	(29,996)	(1,019)	(1,021)
Amortization of prior service cost (credit)	246	246	(1,998)	(1,998)
Recognized actuarial loss	11,648	8,646	1,271	790
Net Periodic Benefit Cost (Credit)	$ 15,587	$ 14,207	$ (328)	$ (521)

For purposes of calculating the expected return on pension plan assets, the market-related value of assets is used, which is based upon fair value. The difference between actual plan asset returns and estimated plan asset returns are amortized equally over a period not to exceed five years.

We estimate amortizations from regulatory assets into net periodic benefit cost during 2014 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 246	$ (1,998)
Accumulated loss	2,226	310

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2013 and 2012. The actuarial assumptions used to compute 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 assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

For 2013 and 2012, we set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. During 2013, we changed the target asset allocation for our pension assets from 50% equity securities / 50% fixed income securities to 35% equity securities / 65% fixed income securities. Considering this information and future expectations for asset returns, we are reducing our long term rate of return on assets assumption from 7.00% for 2013 to 5.80% for 2014.

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 800 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		Other Postretirement Benefits	
	December 31,		December 31,	
	2013	2012	2013	2012
Discount rate	4.55-4.75 %	3.55-3.80 %	3.75-4.20 %	2.25-3.20 %
Expected rate of return on assets	7.00	7.00	7.00	7.00
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.58	3.58
Long-term rate of increase in compensation levels (union)	3.50	3.50	3.50	3.50

The postretirement benefit obligation is calculated assuming that health care costs increased by 8.25% in 2013 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually by 0.25% per year to an ultimate trend of 4.5% by the year 2029. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially fully invested as long-term cash holdings reduce long-term rates of return;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the overall funded status;
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5%, is as follows:

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2013	2012	2013	2012
Domestic debt securities	60.0%	40.0%	40.0%	40.0%
International debt securities	5.0	10.0	—	—
Domestic equity securities	30.0	40.0	50.0	50.0
International equity securities	5.0	10.0	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2013	2012	2013	2012	2013	2012
Cash and cash equivalents	—%	—%	0.1%	—%	1.8%	3.4%
Domestic debt securities	58.6	39.5	64.7	38.3	38.6	37.8
International debt securities	4.9	9.9	4.9	10.6	0.3	—
Domestic equity securities	31.4	40.2	25.3	40.6	50.1	49.8
International equity securities	5.1	10.4	5.0	10.5	9.2	9.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Debt securities consist of U.S. and international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. While the portfolio may invest in high yield securities, the average quality must be rated at least "investment grade" by rating agencies. Performance of fixed income investments is measured by both traditional investment benchmarks as well as relative changes in the present value of the plan's liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks, which are diversified across investment styles such as growth and value. We also invest in international equities with exposure to developing and emerging markets. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the Securities and Exchange Commission (SEC). Investments in a collective investment vehicle are valued by multiplying the investee company's net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT's investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT's investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. In addition, the NorthWestern Corporation pension plan assets also include a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities. The participating group annuity contract is valued based on discounted cash flows of current yields of similar contracts with comparable duration based on the underlying fixed income investments.

The fair value of our plan assets at December 31, 2013, by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 168	$ —	$ 168	$ —
Equity securities: (1)				
US small/mid cap growth	13,764	—	13,764	—
US small/mid cap value	13,664	—	13,664	—
US large cap growth	42,094	—	42,094	—
US large cap value	42,102	—	42,102	—
US large cap passive	47,227	—	47,227	—
Non-US core	20,015	—	20,015	—
Emerging markets	6,250	—	6,250	—
Fixed income securities: (2)				
US core	82,639	—	82,639	—
US passive	44,762	—	44,762	—
Long duration	24,401	—	24,401	—
Long duration investment grade	32,700	—	32,700	—
Long duration passive	24,122	—	24,122	—
Opportunistic	5,876	—	5,876	—
Non-US passive	25,150	—	25,150	—
Active long corporate	83,147	—	83,147	—
Participating group annuity contract	8,271	—	8,271	—
	$ 516,352	$ —	$ 516,352	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 318	$ —	$ 318	$ —
Equity securities: (1)				
US small/mid cap growth	751	—	751	—
US small/mid cap value	736	—	736	—
S&P 500 index	7,321	—	7,321	—
US large cap growth	98	—	98	—
US large cap value	98	—	98	—
US large cap passive	110	—	110	—
Non-US core	1,595	—	1,595	—
Emerging markets	85	—	85	—
Fixed income securities: (2)				
Passive bond market	1,880	—	1,880	—
US core	4,390	—	4,390	—
US passive	107	—	107	—
Long duration	55	—	55	—
Long duration investment grade	79	—	79	—
Long duration passive	55	—	55	—
Opportunistic	261	—	261	—
Non-US passive	57	—	57	—
Active long corporate	187	—	187	—
	$ 18,183	$ —	$ 18,183	$ —

The fair value of our plan assets at December 31, 2012, by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 508		$ 508	$ —
Equity securities: (1)				
US small/mid cap growth	16,229	—	16,229	—
US small/mid cap value	16,297	—	16,297	—
US large cap growth	49,811	—	49,811	—
US large cap value	51,655	—	51,655	—
US large cap passive	56,194	—	56,194	—
Non-US core	36,358	—	36,358	—
Emerging markets	12,713	—	12,713	—
Fixed income securities: (2)				
US core opportunistic	90,742	—	90,742	—
US passive	48,710	—	48,710	—
Long duration	6,455	—	6,455	—
Long duration investment grade	7,091	—	7,091	—
Long duration passive	5,239	—	5,239	—
Non-US passive	46,856	—	46,856	—
Active long corporate	18,540	—	18,540	—
Participating group annuity contract	9,538	—	9,538	—
	$ 472,936	$ —	$ 472,936	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 533	—	$ 533	—
Equity securities: (1)				
US small/mid cap growth	567	—	567	—
US small/mid cap value	567	—	567	—
S&P 500 index	6,360	—	6,360	—
US large cap growth	132	—	132	—
US large cap value	139	—	139	—
US large cap passive	151	—	151	—
Non-US core	1,323	—	1,323	—
Emerging markets	108	—	108	—
Fixed income securities: (2)				
Passive bond market	1,205	—	1,205	—
US core opportunistic	4,440	—	4,440	—
US passive	138	—	138	—
Long duration	16	—	16	—
Long duration investment grade	21	—	21	—
Long duration passive	16	—	16	—
Non-US passive	124	—	124	—
Active long corporate	53	—	53	—
	$ 15,893	$ —	$ 15,893	$ —

(1) This category consists of active and passive managed equity funds, which are invested in multiple strategies to diversify risks and reduce volatility.

(2) This category consists of investment grade bonds of issuers from diverse industries, debt securities issued by international, national, state and local governments, and asset-backed securities. This includes both active and passive managed funds.

For further discussion of the three levels of the fair value hierarchy see Note 11 - Fair Value Measurements.

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements.

Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, we estimate that our minimum annual required contribution for 2014 will be approximately $10.2 million. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

Due to the regulatory treatment of pension costs in Montana, pension expense through 2012 was calculated using the average of our actual and estimated funding amounts from 2005 through 2012. Pension expense for 2013 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2013	2012
NorthWestern Energy Pension Plan (MT)	$ 10,500	$ 10,500
NorthWestern Pension Plan (SD)	1,200	1,200
	$ 11,700	$ 11,700

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

	Pension Benefits	Other Postretirement Benefits
2014	$ 26,648	$ 3,585
2015	27,855	3,494
2016	29,850	3,388
2017	31,016	3,237
2018	32,472	3,082
2019-2023	182,212	12,107

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, 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. Matching contributions for the year ended December 31, 2013 and 2012 were $7.8 million and $7.2 million, respectively.

(19) Stock-Based Compensation

We grant stock-based awards through our 2005 Long-Term Incentive Plan (LTIP), which includes restricted stock awards and performance share awards. As of December 31, 2013, there were 662,507 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Restricted Stock and Performance Share Awards

Performance share awards were granted under the 2005 LTIP during 2013 and 2012. With these awards, shares will vest if, at the end of the three-year performance period, we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. These awards contain both a market and performance based component. The performance goals for these awards are independent of each other and equally weighted, and are based on two metrics: (i) cumulative net income and average return on equity; and (ii) total shareholder return (TSR) relative to a peer group.

Fair value is determined for each component of the performance share awards. The fair value of the net income component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of restricted stock is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends. The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2013	2012
Risk-free interest rate	0.44%	0.38%
Expected life, in years	3	3
Expected volatility	16.3% to 25.4%	20.2% to 34.2%
Dividend yield	3.9%	4.1%

The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of and changes during the year ended December 31, 2013, are as follows:

	Performance Share Awards		Restricted Stock Awards	
	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	186,755	$ 22.64	1,000	$ 24.77
Granted	88,592	32.97	2,500	35.78
Vested	(100,402)	20.48	(3,500)	32.63
Forfeited	(1,299)	25.33	—	—
Remaining nonvested grants	173,646	$ 29.14	—	$ —

We recognized compensation expense of $2.4 million and $2.8 million for the years ended December 31, 2013 and 2012, respectively, and a related income tax benefit of $1.5 million and $0.4 million for the years ended December 31, 2013 and 2012, respectively. As of December 31, 2013, we had $3.0 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as other paid-in capital in our Balance Sheets. The cost is expected to be recognized over a weighted-average period of 2.3 years. The total fair value of shares vested was $2.2 million and $2.0 million for the years ended December 31, 2013 and 2012, respectively.

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. These awards are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends.

A summary of nonvested shares as of and changes during the year ended December 31, 2013, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	17,537	$ 27.70
Granted	9,091	35.14
Vested	—	—
Forfeited	—	—
Remaining nonvested grants	26,628	$ 30.24

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 Internal Revenue 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. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's 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 of years (not to exceed 10 years). During the years ended December 31, 2013 and 2012, DSUs issued to members of our Board totaled 33,837 and 31,801, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2013 and 2012 was approximately $3.6 million and $0.9 million, respectively.

(20) Common Stock

We have 250,000,000 shares authorized 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. Of these shares, 2,265,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 19 - Stock-Based Compensation.

In April 2012, we entered into an Equity Distribution Agreement pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. During 2013, we issued 1,381,494 shares of our common stock at an average price of $41.61 per share, for net proceeds of $56.8 million. During the three months ended December 31, 2013, we issued 278,914 shares at an average price of $46.17, for net proceeds of $12.7 million, which is net of sales commissions of approximately $129,000, and other fees.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 34,552 and 22,789 during the years ended December 31, 2013 and 2012, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

(21) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the Public Utility Regulatory Policies Act. The QFs require us to purchase minimum amounts of energy at prices ranging from $74 to $136 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.1 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $0.9 billion through 2029. The present value of the remaining QF liability is recorded in our Balance Sheets as a regulatory disallowance liability pursuant to ASC 980. The following summarizes the change in the QF liability (in thousands):

	December 31, 2013	December 31, 2012
Beginning QF liability	$ 136,652	$ 184,187
Gain on CELP arbitration decision	—	(47,894)
Unrecovered amount	(10,647)	(12,014)
Interest expense	10,443	12,373
Ending QF liability	$ 136,448	$ 136,652

See Note 3 - Acquisitions and Significant Events for additional discussion related to the adjustment of the QF liability related to the CELP arbitration decision in 2012.

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

	Gross Obligation	Recoverable Amounts	Net
2014	$ 67,283	$ 56,025	$ 11,258
2015	69,606	56,598	13,008
2016	71,598	57,188	14,410
2017	73,622	57,789	15,833
2018	75,688	58,401	17,287
Thereafter	724,574	567,215	157,359
Total	$ 1,082,371	$ 853,216	$ 229,155

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 28 years. Costs incurred under these contracts were approximately $379.4 million and $340.8 million for the years ended December 31, 2013 and 2012, respectively. As of December 31, 2013, our commitments under these contracts are $305.8 million in 2014, $202.6 million in 2015, $160.7 million in 2016, $136.7 million in 2017, $108.6 million in 2018, and $1,143.4 million thereafter. These commitments are not reflected in our Financial Statements.

Environmental Liabilities

The operation of electric generating, transmission and distribution facilities, and gas gathering, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources, avian and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are implemented, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, the majority of our environmental reserve relates to the remediation of former manufactured gas plant sites owned by us. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

Our liability for environmental remediation obligations is estimated to range between $27.3 million to $35.0 million, primarily for manufactured gas plants discussed below. As of December 31, 2013, we have a reserve of approximately $29.9 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. Over time, as costs become determinable, we may seek authorization to recover such costs in rates or seek insurance reimbursement as applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our financial position or results of operations.

Manufactured Gas Plants - Approximately $23.3 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies and implementing remedial actions at the Aberdeen site pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources (DENR). Our current reserve for remediation costs at this site is approximately $12.0 million, and we estimate that approximately $9.0 million of this amount will be incurred during the next five years.

We also own sites in North Platte, Kearney and Grand Island, Nebraska on which former manufactured gas facilities were located. In February 2011, the Nebraska Department of Environmental Quality (NDEQ) completed an Abbreviated Preliminary Assessment and Site Investigation Report for Grand Island, which recommended additional ground water testing. In April of 2012, we received a letter from NDEQ regarding a recently completed Vapor Intrusion Assessment Report and an invitation to join NDEQ's Voluntary Cleanup Program (VCP). We declined NDEQ's offer to join its VCP and committed to conducting a limited soil vapor investigation, which was completed in July 2012. We are currently working independently to fully characterize the nature and extent of impacts associated with the Grand Island former manufactured gas plant as well as the North Platte and Kearney sites. Our reserve estimate includes assumptions for site assessment and remedial action work. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

In addition, we own or have responsibility for 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 remediation activities, but required preparation of a groundwater monitoring plan. The Butte and Helena sites were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to soil and groundwater impacts. Voluntary soil and coal tar removals were conducted in the past at the Butte and Helena locations in accordance with MDEQ requirements. We have conducted additional groundwater monitoring at the Butte and Missoula sites and, at this time, we believe natural attenuation should address the conditions at these sites; however, additional groundwater monitoring will be necessary and additional monitoring wells will be installed at the Butte site. Monitoring of groundwater at the Helena site is ongoing and will be necessary for an extended period of time. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action at the Helena site or if any additional actions beyond monitored natural attenuation will be required.

Global Climate Change - National and international actions have been initiated to address global climate change and the contribution of emissions of greenhouse gases (GHG) including, most significantly, carbon dioxide. These actions include legislative proposals, Executive and Environmental Protection Agency (EPA) actions at the federal level, actions at the state level, and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny due to their level of GHG emissions. We have joint ownership interests in four electric generating plants, all of which are coal fired and operated by other companies. We have undivided interests 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.

While numerous bills have been introduced that address climate change from different perspectives, including through direct regulation of GHG emissions, the establishment of cap and trade programs and the establishment of Federal renewable portfolio standards, Congress has not passed any federal climate change legislation and we cannot predict the timing or form of any potential legislation. In the absence of such legislation, EPA is presently regulating GHG emissions of the very largest emitters, including large power plants, under the Clean Air Act, and specifically under the Prevention of Significant Deterioration (PSD) pre-construction permit and Title V operating permit programs.

On January 8, 2014, the EPA reproposed New Source Performance Standards (NSPS) that specify permissible levels of GHG emissions from newly-constructed fossil fuel-fired electric generating units. As directed by President Obama's June 25, 2013, Climate Action Plan, the EPA also intends to establish, pursuant to Section 111(d) of the Clean Air Act, carbon dioxide emissions standards for existing fossil fuel fired electric generating units. EPA plans to propose regulations and guidelines addressing GHG emissions for existing units by June 1, 2014, and finalize those guidelines by June 1, 2015. States must then submit their individual plans for reducing power plants' GHG emissions to EPA by June 30, 2016. Thus, it is possible that existing power plants may be required to comply with GHG performance standards as soon as July 2016.

The U.S. Supreme Court is expected to hear oral arguments on February 24, 2014 on the challenge to EPA's GHG regulations, including the Tailoring Rule which limits the sources subject to GHG permitting requirements to the largest fossil-fueled power plants. It is conceivable that the Court could invalidate EPA's PSD and Title V Tailoring Rule, but still leave power plants subject to anticipated new and existing source performance standards for GHG.

Physical impacts of climate change may present potential risks for severe weather, such as floods and tornadoes, in the locations where we operate or have interests. Furthermore, requirements to reduce GHG emissions from stationary sources could cause us to incur material costs of compliance and increase our costs of procuring electricity. In addition, we believe future legislation and regulations that affect GHG emissions from power plants are likely, although technology to efficiently capture, remove and/or sequester such emissions may not be available within a timeframe consistent with the implementation of such requirements. We cannot predict with any certainty whether these risks will have a material impact on our operations.

Coal Combustion Residuals (CCRs) - In June 2010, the EPA proposed two approaches to regulating the disposal and management of CCRs under the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and scrubber wastes. Under one approach, the EPA would regulate CCRs as special wastes subject to regulation under subtitle C, the hazardous waste provisions, of RCRA. This approach would have significant impacts on coal-fired plants, and would require plants to retrofit their operations to comply with hazardous waste requirements from the generation of CCRs and associated waste waters through transportation and disposal. This could also have a negative impact on the beneficial use of CCRs and the current markets associated with such use. The second approach would regulate CCRs as a solid waste under Subtitle D of RCRA. This approach would only affect disposal, most significantly any wet disposal, of CCRs. In a January 2014 consent decree in the case *Appalachian Voices v. McCarthy*, the EPA agreed to take final action with respect to the CCR regulations by December 19, 2014. In addition, legislation has been introduced in Congress to regulate coal ash. We cannot predict at this time the final requirements of any CCR regulations or legislation and what impact, if any, they would have on us, but the costs of complying with any such requirements could be significant.

Water Intakes and Discharges - Section 316(b) of the Federal Clean Water Act (CWA) requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. Permits required for existing facilities are to be developed by the individual states using their best professional judgment until the EPA takes action to address several court decisions that rejected portions of previous rules and confirmed that the EPA has discretion to consider costs relative to benefits in developing cooling water intake structure regulations. In March 2011, the EPA proposed a rule to address impingement and entrainment of aquatic organisms at existing cooling water intake structures. Pursuant to a settlement agreement, the EPA was required to take final action on the regulations by January 14, 2014, but the EPA did not meet the settlement deadline and it is working to complete the final rule for cooling water intakes as soon as possible. When a final rule is issued and implemented, additional capital and/or increased operating costs may be required. The costs of complying with any such final water intake standards are not currently determinable, but could be significant.

In April 2013, the EPA proposed CWA regulations to address mercury, arsenic, lead, and selenium in water discharged from power plants. The proposed regulations include a variety of options for whether and how these different waste streams should be treated. The EPA is expected to evaluate comments on all of these options prior to enacting final regulations. Under the proposed approach, new requirements for existing power plants would be phased in between 2017 and 2022. The EPA also announced its intention to align this CWA rule with the related rule for CCRs discussed above. The EPA is under a consent decree to take final action by May 22, 2014. The EPA estimates that over half of the existing power plants will not incur costs under any of the proposed options because many power plants already have the technology and procedures in place to meet the proposed pollution control standards; however, it is too early to determine whether the impacts of these rules will be material.

Clean Air Act Rules and Associated Emission Control Equipment Expenditures

The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act that could require the installation of emission control equipment at the generation plants where we have joint ownership.

The Clean Air Visibility Rule was issued by the EPA in June 2005, to address regional haze in national parks and wilderness areas across the United States. The Clean Air Visibility Rule requires the installation and operation of Best Available Retrofit Technology (BART) to achieve emissions reductions from designated sources (including certain electric generating units) that are deemed to cause or contribute to visibility impairment in such 'Class I' areas.

In December 2011, the EPA issued a final rule relating to Mercury and Air Toxics Standards (MATS). Among other things, the MATS set stringent emission limits for acid gases, mercury, and other hazardous air pollutants from new and existing electric generating units. Facilities that are subject to the MATS must come into compliance within three years after the effective date of the rule (or by 2015) unless a one year extension is granted on a case-by-case basis. Numerous challenges to the MATS have been filed with the EPA and in Federal court and we cannot predict the outcome of such challenges.

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to reduce emissions from electric generating units that interfere with the ability of downwind states to achieve ambient air quality standards. Under CSAPR, significant reductions in emissions of nitrogen oxide (NOx) and sulfur dioxide (SO2) were to be required in certain states beginning in 2012. On December 10, 2013, the Supreme Court heard oral arguments on the review of the D.C. Circuit's 2012 decision which vacated the CSAPR.

In October 2013, the Supreme Court denied certiorari in *Luminant Generation Co v. EPA*, which challenged the EPA's current approach to regulating air emissions during startup, shutdown and malfunction (SSM) events. As a result, fossil fuel power plants may need to address SSM in their permits to reduce the risk of enforcement or citizen actions.

In September 2012, a final Federal Implementation Plan for Montana was published in the Federal Register to address regional haze. As finalized, Colstrip Unit 4 does not have to improve removal efficiency for pollutants that contribute to regional haze. By 2018, Montana, or EPA, must develop a revised Plan that demonstrates reasonable progress toward eliminating man made emissions of visibility impairing pollutants, which could impact Colstrip Unit 4. In November 2012, National Parks Conservation Association, Montana Environmental Information Center, and Sierra Club jointly filed a petition for review of the Federal Implementation Plan in the U.S. Court of Appeals for the Ninth Circuit. Montana Environmental Information Center and Sierra Club have challenged the EPA's decision not to require any emissions reductions from Colstrip Units 3 and 4. At this time, we cannot predict or determine the timing or outcome of this petition.

We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa and Montana that are or may become subject to various regulations that have been issued or proposed under the Clean Air Act, as discussed below.

South Dakota. The South Dakota DENR determined that the Big Stone Plant, of which we have a 23.4% ownership, is subject to the BART requirements of the Regional Haze Rule. South Dakota DENR's State Implementation Plan (SIP) was approved by the EPA in May 2012. Under the SIP, the Big Stone plant must install and operate a new BART compliant air quality control system (AQCS) to reduce SO2, NOx and particulate emissions as expeditiously as practicable, but no later than five years after the EPA's approval of the SIP. The current project cost for the AQCS is estimated to be approximately $405 million (our share is 23.4%) and it is expected to be operational by 2016. As of December 31, 2013, we have capitalized costs of approximately $40.5 million related to this project.

Our incremental capital expenditure projections include amounts related to our share of the BART at Big Stone based on current estimates. We could, however, face additional capital or financing costs. We will seek to recover any such costs through the regulatory process. The South Dakota Public Utilities Commission has historically allowed timely recovery of the costs of environmental improvements; however, there is no precedent on a project of this size.

Based on the finalized MATS, Big Stone will meet the requirements by installing the AQCS system and using activated carbon injection for mercury control. In August 2013, the South Dakota DENR granted Big Stone a one year extension to comply with MATS, such that the new compliance deadline is April 16, 2016. New mercury emissions monitoring equipment will also be required.

North Dakota. The North Dakota Regional Haze SIP requires the Coyote generating facility, of which we have 10% ownership, to reduce its NOx emissions. Coyote must install control equipment to limit its NOx emissions to 0.5 pounds per million Btu as calculated on a 30-day rolling average basis, including periods of start-up and shutdown, beginning on July 1, 2018. The current estimate of the total cost of the project is approximately $9.0 million (our share is 10.0%).

Based on the finalized MATS, Coyote will meet the requirements by using activated carbon injection for mercury control.

Iowa. The Neal #4 generating facility, of which we have an 8.7% ownership, is installing a scrubber, a baghouse, activated carbon and a selective non-catalytic reduction system to comply with national ambient air quality standards and the MATS. The plant began incurring costs in 2011 and the project was substantially completed in 2013. Our share (8.7%) of the capitalized costs related to this project were approximately $22.6 million.

Montana. Colstrip Unit 4, a coal fired generating facility in which we have a 30% interest, is currently controlling emissions of mercury under regulations issued by the State of Montana, which are stricter than the Federal MATS. The owners do not believe additional equipment will be necessary to meet the MATS for mercury, and anticipate meeting all other expected MATS emissions limitations required by the rule without additional costs except those costs related to increased monitoring frequency. These additional costs are not expected to be significant.

See 'Legal Proceedings - Colstrip Litigation' below for discussion of Sierra Club litigation.

Other - We continue to manage equipment containing polychlorinated biphenyl (PCB) oil 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.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

Colstrip Litigation

On March 6, 2013, the Sierra Club and the MEIC (Plaintiffs) filed suit in the United States District Court for the District of Montana against the six individual owners of Colstrip, including us, as well as the operator or managing agent of the station. On September 27, 2013, Plaintiffs filed an Amended Complaint for Injunctive and Declaratory Relief. The original complaint included 39 claims for relief based upon alleged violations of the Clean Air Act and the Montana State Implementation Plan. The Amended Complaint drops claims associated with projects completed before 2001, the Title V claims and the opacity claims. There are now a total of 23 claims.

In the Amended Complaint, Plaintiffs have identified physical changes made at Colstrip between 2001 and 2012, which they allege have increased emissions of SO2, NOx and particulate matter and were "major modifications" subject to permitting requirements under the Clean Air Act. They also have alleged violations of the requirements related to Part 70 Operating

Permits. Plaintiffs seek injunctive and declaratory relief, civil penalties (including $100,000 of civil penalties to be used for beneficial environmental projects), and recovery of their attorney fees.

On May 3, 2013, the Colstrip owners and operator filed a partial motion to dismiss, seeking dismissal of 36 of the 39 claims asserted in the original complaint. The motion was not ruled upon and the Colstrip owners filed a second motion to dismiss the Amended Complaint on October 11, 2013, incorporating parts of the first motion and supplementing it with new authorities and with regard to new claims contained in the Amended Complaint. The Court has not ruled on the second motion to dismiss.

On September 12, 2013, Plaintiffs filed a motion for partial summary judgment as to the applicable method for calculating emissions increases from modifications. The Court has not ruled on Plaintiffs' motion for partial summary judgment.

We intend to vigorously defend this lawsuit. Due to the preliminary nature of the lawsuit, at this time, we cannot predict an outcome, nor is it reasonably possible to estimate the amount or range of loss, if any, that would be associated with an adverse decision.

Other Legal Proceedings

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

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	569,395	1,443,520	-60.56%
5	**Total Intangible Plant**	696,437	1,570,562	-55.66%
6				
7	**Production Plant**			
8	2325 Gas Leaseholds	77,594,316	23,055,107	236.56%
9	2327 Field Compressor Structure	12,326	-	-
10	2328 Field Mea & Reg Structure	262,707	-	-
11	2330 Well Construction	4,590,996	2,726,027	68.41%
12	2331 Well Equipment	4,618,343	2,751,933	67.82%
13	2332 Field Lines	1,374,498	1,627,794	-15.56%
14	2333 Field Compressor Equipment	666,736	682,240	-2.27%
15	2334 Measuring & Regulating Equip.	211,157	634,885	-66.74%
16	2337 Other Equipment	99,431	634,885	-84.34%
17	**Total Production Plant**	89,430,510	31,477,986	184.10%
18				
19	**Underground Storage Plant**			
20	2350 Land and Land Rights	4,830,741	4,804,300	0.55%
21	2351 Structures and Improvements	3,142,768	3,157,283	-0.46%
22	2352 Wells	7,863,030	7,922,147	-0.75%
23	2353 Lines	12,545,864	12,545,864	0.00%
24	2354 Compressor Station Equipment	7,438,999	7,321,601	1.60%
25	2355 Measuring & Regulating Equip.	3,006,774	3,006,774	0.00%
26	2356 Purification Equipment	397,931	397,931	0.00%
27	2357 Other Equipment	889,291	889,291	0.00%
28	**Total Underground Storage Plant**	40,115,398	40,045,191	0.18%
29				
30	**Transmission Plant**			
31	2365 Rights of Way	8,327,963	8,236,975	1.10%
32	2366 Structures and Improvements	12,963,931	12,804,458	1.25%
33	2367 Mains	196,480,041	194,620,594	0.96%
34	2368 Compressor Station Equipment	23,390,873	22,496,384	3.98%
35	2369 Meas. & Reg. Station Equipment	17,092,097	16,229,357	5.32%
36	2370 Communication Equipment	-	-	-
37	2371 Other Equipment	165,972	165,972	0.00%
38	**Total Transmission Plant**	258,420,877	254,553,740	1.52%
39				
40	**Distribution Plant**			
41	2374 Land and Land Rights	1,026,260	994,374	3.21%
42	2375 Structures and Improvements	90,524	90,524	0.00%
43	2376 Mains	132,313,079	126,947,999	4.23%
44	2377 Compressor Station Equipment	-	-	-
45	2378 M&R Station Equip.-General	3,334,516	3,076,231	8.40%
46	2379 M&R Station Equip.-City Gate	-	-	-
47	2380 Services	65,075,751	62,619,267	3.92%
48	2381 Customers Meters and Regulators	61,542,721	59,899,973	2.74%
49	2382 Meter Installations	-	-	-
50	2383 House Regulators	-	-	-
51	2384 House Regulator Installations	-	-	-
52	2385 M&R Station Equip.-Industrial	97,561	97,561	0.00%
53	2386 Other Prop. on Customers' Premises	-	-	-
54	2387 Other Equipment	26,216	26,216	0.00%
55	**Total Distribution Plant**	263,506,628	253,752,145	3.84%

Sch. 19	cont. MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP & HPC)			
	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	2,198,785	1,737,254	26.57%
5	2391 Office Furniture and Equipment	184,312	224,964	-18.07%
6	2392 Transportation Equipment	9,647,178	9,130,442	5.66%
7	2393 Stores Equipment	28,927	28,927	0.00%
8	2394 Tools, Shop & Garage Equipment	5,429,479	5,200,707	4.40%
9	2395 Laboratory Equipment	705,422	772,009	-8.63%
10	2396 Power Operated Equipment	3,044,542	2,912,568	4.53%
11	2397 Communication Equipment	3,403,963	4,104,535	-17.07%
12	2398 Miscellaneous Equipment	110,097	110,582	-0.44%
13	2399 Other Tangible Property	-	-	-
14	**Total General Plant**	24,854,380	24,323,663	2.18%
15	**Total Gas Plant in Service**	677,024,230	605,723,287	11.77%
16				
17	4101 Gas Plant Allocated from Common	30,323,503	29,845,039	1.60%
18	2105 Gas Plant Held for Future Use	4,900	4,900	0.00%
19	2107 Gas Construction Work in Progress	7,475,617	6,580,818	13.60%
20	2117 Gas in Underground Storage	48,401,767	50,375,320	-3.92%
21				
22				
23	**TOTAL GAS PLANT**	$763,230,017	$692,529,364	10.21%
24				
25				
26	**CONSOLIDATED**	December 31,		
27	**PLANT IN SERVICE**	2013	2012	
28				
29	Montana Electric	$ 2,390,960,783	$ 2,316,701,843	
30	Yellowstone National Park	13,618,264	13,592,613	
31	Montana Natural Gas (Includes CMP)	677,024,230	605,723,287	
32	Common	86,730,756	84,766,822	
33	Townsend Propane	1,519,564	1,516,050	
34	South Dakota Electric	580,354,887	492,604,252	
35	South Dakota Natural Gas	161,401,195	157,452,886	
36	South Dakota Common	47,886,249	44,774,141	
37	Asset Retirement Obligation	15,205,199	6,376,126	
38	**TOTAL PLANT**	$ 3,974,701,127	$ 3,723,508,020	

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	$31,040,315	$4,236,149	$1,664,705	8.33%
4					
5	Underground Storage	40,032,064	22,306,977	21,685,496	1.68%
6					
7	Other Storage	-	-	-	-
8					
9	Transmission	253,615,632	96,456,464	93,176,120	1.69%
10					
11	Distribution	253,592,685	114,890,916	109,806,117	2.62%
12					
13	General and Intangible	25,588,295	12,293,784	12,561,533	8.10%
14					
15	Common	28,841,928	12,169,702	13,344,316	6.63%
16					
17					
18	**Total Accum Depreciation**	$632,710,919	$262,353,992	$252,238,287	2.69%
19					
20					
21					

22	**Consolidated**	December 31,	
23	**Accumulated Depreciation**	2013	2012
24			
25	Montana Electric	$ 946,560,375	$901,894,297
26	Yellowstone National Park	9,224,628	8,955,866
27	Montana Natural Gas (Includes CMP)	250,184,290	238,893,971
28	Common	33,281,451	36,018,027
29	Townsend Propane	729,083	691,992
30	South Dakota Electric	261,015,837	254,603,383
31	South Dakota Natural Gas	72,029,599	68,599,519
32	South Dakota Common	13,624,280	12,389,577
33	Acquisition Writedown	62,208,066	66,471,868
34	Basin Creek Capital Lease	15,078,542	13,068,062
35	FIN 47	1,503,510	1,252,831
36	CWIP-Capital Retirement Clearing	-6,741,583	-4,589,625
37	**Total Consolidated Accum Depreciation**	$1,658,698,078	$1,598,249,768

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	154 Plant Materials & Operating Supplies			
3	Assigned and Allocated to:			
4	Operation & Maintenance	-	-	-
5	Construction	-	-	-
6	Storage Plant	$ 156,253	$ 137,691	13.48%
7	Transmission Plant	1,006,572	875,257	15.00%
8	Distribution Plant	1,872,259	1,996,315	-6.21%
9				
10	**Total MT Materials and Supplies**	$3,035,084	$3,009,263	0.86%
11				
12				
13	**Consolidated**	December 31,		
14	**Materials and Supplies**	2013	2012	
15				
16	Montana Natural Gas	$3,035,084	$3,009,263	
17	Montana Electric	16,474,362	15,692,303	
18	South Dakota	7,281,627	6,813,310	
19				
20	**Total Consolidated Materials and Supplies**	$26,791,073	$25,514,876	

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - NATURAL GAS			
	Commission Accepted - Most Recent 1/	% Capital Structure	% Cost Rate	Weighted Cost
2	Docket Number: 2012.9.94			
3	Order Number : 7249e			
4	Effective Date : June 1, 2013			
6	Common Equity	47.65%	9.80%	4.67%
7	Long Term Debt	52.35%	5.37%	2.81%
9	**TOTAL**	100.00%		7.48%

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 93,982,666	$ 98,406,342	-4.50%
4	Noncash Charges (Credits) to Income:			
5	Depreciation	109,962,010	107,677,003	2.12%
6	Amortization, Net	2,858,210	(1,676,537)	270.48%
7	Other Noncash Charges to Net Income, Net	9,033,466	(40,823,868)	122.13%
8	Deferred Income Taxes, Net	47,108,947	65,871,867	-28.48%
9	Investment Tax Credit Adjustments, Net	(334,950)	(375,635)	10.83%
10	Change in Operating Receivables, Net	(26,616,918)	7,549,047	>-300.00%
11	Change in Materials, Supplies & Inventories, Net	537,664	5,367,735	-89.98%
12	Change in Operating Payables & Accrued Liabilities, Net	16,651,383	21,727,054	-23.36%
13	Allowance for Funds Used During Construction (AFUDC)	(5,049,543)	(4,846,070)	-4.20%
14	Change in Other Assets & Liabilities, Net	(15,444,979)	13,109,501	-217.82%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,416,238)	10,657,063	-122.67%
17	Change in Regulatory Assets	(36,983,179)	(34,461,811)	-7.32%
18	Change in Regulatory Liabilities	(4,719,283)	(780,115)	>-300.00%
19	**Net Cash Provided by Operating Activities**	188,569,255	247,401,576	-23.78%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(300,103,374)	(322,474,752)	6.94%
22	(Net of AFUDC)			
23	Proceeds from Sale of Assets	3,765,819	261,793	>300.00%
24	**Net Cash Used in Investing Activities**	(296,337,555)	(322,212,959)	8.03%
25	**Cash Flows from Financing Activities:**			
26	Proceeds from Issuance of:			
27	Issuance of Long-Term Debt	100,000,000	150,000,000	-33.33%
28	Credit Facilities Borrowings	-	-	100.00%
29	Issuance of Short Term Borrowings, Net	18,015,652	-	100.00%
30	Proceeds From Issuance of Common Stock, Net	56,825,170	28,477,203	99.55%
31	Payments for Retirement of:			
32	Capital Lease Obligations, Net	(148,500)	(153,358)	3.17%
33	Repayments of Short Term Borrowings, Net	-	(43,999,590)	100.00%
34	Dividends on Common Stock	(57,683,552)	(54,245,888)	-6.34%
35	Other Financing Activities:			
36	Debt Financing Costs	(7,593,330)	(943,014)	>-300.00%
37	Treasury Stock Activity	(1,041,694)	(429,673)	-142.44%
38	**Net Cash (Used in)/Provided by Financing Activities**	108,373,746	78,705,680	37.69%
39	**Net (Decrease)/Increase in Cash and Cash Equivalents**	605,446	3,894,297	-84.45%
40	**Cash and Cash Equivalents at Beginning of Year**	9,822,114	5,927,817	65.70%
41	**Cash and Cash Equivalents at End of Year**	$ 10,427,560	$ 9,822,114	6.16%
42				
43	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
44	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
45	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
46	Pipeline Corporation.			
47				

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 %
First Mortgage Bonds								
6.34% Series, Due 2019	03/26/09	04/01/19	$ 250,000,000	$ 247,657,313	$ 249,912,062	6.34%	$ 16,514,170	6.61%
5.71% Series, Due 2039	10/15/09	10/15/39	55,000,000	54,450,000	55,000,000	5.71%	3,158,845	5.74%
6.04% Series, Due 2016	09/13/06	09/01/16	150,000,000	148,302,298	149,980,400	6.04%	9,308,114	6.21%
5.01% Sr Notes ($225M), Due 2025	05/27/10	05/01/25	161,000,000	160,075,635	161,000,000	5.01%	8,585,842	5.33%
4.15% Series($60M), Due 2042	08/10/12	08/10/42	60,000,000	59,623,329	60,000,000	4.15%	2,502,562	4.17%
4.30% Series($60M), Due 2052	08/10/12	08/10/52	40,000,000	39,748,886	40,000,000	4.30%	1,726,280	4.32%
4.85% Series($15M), Due 2043	12/19/13	12/19/43	15,000,000	14,929,953	15,000,000	4.85%	729,835	4.87%
3.99% Series($35M), Due 2028	12/19/13	12/19/28	35,000,000	34,836,556	35,000,000	3.99%	1,407,396	4.02%
Total First Mortgage Bonds			$ 766,000,000	$ 759,623,971	$ 765,892,462		$ 43,933,045	5.74%
Pollution Control Bonds								
4.65% Series, Due 2023	04/27/06	08/01/23	$ 170,205,000	$ 164,451,956	$ 170,205,000	4.650%	$ 8,467,855	4.98%
Total Pollution Control Bonds			$ 170,205,000	$ 164,451,956	$ 170,205,000		$ 8,467,855	4.98%
TOTAL LONG TERM DEBT			$ 936,205,000	$ 924,075,926	$ 936,097,462		$ 52,400,899	5.60%

This schedule does not reflect capital leases, which are comprised of Fleet Leases and the Basin Creek contract. These amounts total $107,658 and $31,449,475 respectively.

Sch. 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	NOT APPLICABLE									
3										
4										
5										
6										
7										
8										
9										
10										
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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	37,224,836	$25.54				$37.03	$35.06	
February	37,397,001	25.80				39.20	36.88	
March	37,805,238	25.81	$1.01	$0.38		40.35	38.53	
April	37,884,938	26.03				43.14	39.57	
May	38,240,974	26.26				43.17	40.34	
June	38,448,254	26.07	0.37	0.38		41.67	38.12	
July	38,457,905	26.18				44.33	39.08	
August	38,461,118	26.35				42.99	40.05	
September	38,462,477	26.11	0.41	0.38		45.85	39.68	
October	38,463,262	26.23				47.18	43.92	
November	38,744,356	26.69				46.61	43.45	
December	38,745,624	26.60	0.67	0.38		43.96	41.31	
TOTAL Year End	38,144,852	$26.60	$2.46	$1.52	38.21%	$43.32		17.6

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2013.

Sch. 27	MONTANA EARNED RATE OF RETURN - GAS		
Description	This Year	Last Year	% Change
Rate Base			
101 Plant in Service	$643,857,971	$600,885,145	7.15%
108 Accumulated Depreciation	(260,102,986)	(247,211,361)	-5.21%
Net Plant in Service	$383,754,985	$353,673,784	8.51%
Additions:			
154, 156 Materials & Supplies	$5,735,445	$4,895,685	17.15%
165 Prepayments			
Other Additions 1/	79,422,840	59,820,170	32.77%
Total Additions	$85,158,285	$64,715,855	31.59%
Deductions:			
190 Accumulated Deferred Income Taxes	$51,019,233	$32,973,851	54.73%
252 Customer Advances for Construction	7,287,049	8,920,545	-18.31%
255 Accumulated Def. Investment Tax Credits			
Other Deductions	26,853,199	28,354,267	-5.29%
Total Deductions	$85,159,481	$70,248,663	21.23%
Total Rate Base	$383,753,789	$348,140,976	10.23%
Adjusted Rate Base	$383,753,789	$348,140,976	10.23%
Net Earnings	$25,514,498	$16,829,221	51.61%
Rate of Return on Average Rate Base	6.649%	4.834%	37.54%
Rate of Return on Average Equity 2/	8.641%	4.581%	88.63%
Major Normalizing and Commission Ratemaking Adjustments			
Rate Schedule Revenues	($468,400)	$2,852,044	-116.42%
Funding Trust Regulatory Liability	0	1,140,101	-100.00%
Non-Allowables:			
Advertising	207,807	114,323	81.77%
Dues, Contributions, Other	26,895	32,400	-16.99%
Associated Income Taxes 3/	1,166,560	(377,507)	>300.00%
Total Adjustments	$932,862	$3,761,361	-75.20%
Revised Net Earnings	$26,447,359	$20,590,582	28.44%
Rate Base Adjustment			
Stipulation with MCC 4/	($11,098,508)	($11,524,881)	3.70%
Revised Rate Base	$372,655,281	$336,616,095	10.71%
Adjusted Rate of Return on Average Rate Base	7.097%	6.117%	16.02%
Adjusted Rate of Return on Average Equity 2/	8.819%	6.290%	40.20%

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

2/ Return on Equity calculated using the capital structure approved in Docket No. D2012.9.94.

3/ Associated Income taxes include an interest synchronization adjustment based upon the approved capital structure in Docket No. D2012.9.94.

4/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting one-third of the $38.8 million allocated to natural gas as a rate base reduction.

Sch. 27	cont. MONTANA EARNED RATE OF RETURN - GAS			
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset 1/	$44,311,907	$24,770,424	78.89%
4	Gas Stored Underground	32,096,313	32,096,313	0.00%
5	Cost of Refinancing Debt	2,754,414	2,953,433	-6.74%
6	MPSC/MCC Taxes	260,206	-	-
7				
8	**Total Other Additions**	$79,422,840	$59,820,170	32.77%
9				
10	**Detail - Other Deductions**			
11	Personal Injury and Property Damage	$3,267,344	$1,870,308	74.70%
12	Storage Gas Sales 2000 & 2001	11,040,849	11,461,365	-3.67%
13	Gross Cash Requirements	12,545,006	11,087,961	13.14%
14	Bond Refinancing CTC - GP	0	940,181	-100.00%
15	Bond Refinancing CTC - RA	0	2,994,452	-100.00%
16	MPSC/MCC Taxes	-	-	-
17				
18	**Total Other Deductions**	$26,853,199	$28,354,267	-5.29%

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)	$ 707,347,733
5	105	Plant Held for Future Use	4,900
6	107	Construction Work in Progress	7,475,617
7	117	Gas in Underground Storage	48,401,767
8	151-163	Materials & Supplies	3,035,084
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	262,353,992
11	252	Contributions in Aid of Construction	5,418,393
12	**NET BOOK COSTS**		498,492,716
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	200,239,710
17			
18	**Total Operating Revenues**		200,239,710
19			
20	401-402	Other Operating Expenses (including regulatory amortizations)	127,812,285
21	403-407	Depreciation & Amortization Expenses	18,163,738
22	408.1	Taxes Other than Income Taxes	27,714,846
23	409-411	Federal & State Income Taxes	1,034,343
24			
25	**Total Operating Expenses**		174,725,212
26	**Net Operating Income**		25,514,498
27			
28	415-421.1	Other Income	622,796
29	421.2-426.5	Other Deductions	65,970
30	**NET INCOME BEFORE INTEREST EXPENSE**		$ 26,071,324
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	160,511
34		Commercial	22,457
35		Industrial	265
36		Other (including interdepartmental)	160
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		183,393
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	79.4
41		Average Annual Residential Cost per (Dkt)	$8.77
42		Average Residential Monthly Bill	$57.99
43			
44		Plant in Service (Gross) per Customer	$3,857

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,150	471	76	2	549
2	Amsterdam	180	55	9	-	64
3	Anaconda	9,298	3,349	319	5	3,673
4	Augusta	309	193	45	1	239
5	Belfry	218	4	-	-	4
6	Belgrade	7,389	5,260	802	1	6,063
7	Big Mountain	-	205	33	-	238
8	Big Sandy	598	292	69	-	361
9	Big Timber	1,641	917	183	8	1,108
10	Bigfork	4,270	1,365	211	-	1,576
11	Billings	104,170	19	3	2	24
12	Bonner	1,663	65	8	-	73
13	Boulder	1,183	472	81	2	555
14	Bozeman	37,280	20,539	3,236	9	23,784
15	Browning	2,801	1,007	152	3	1,162
16	Buffalo	-	5	-	-	5
17	Butte	33,525	12,656	1,414	36	14,106
18	Cardwell	50	17	4	-	21
19	Carter	58	28	8	-	36
20	Chester	847	365	133	3	501
21	Chinook	1,203	697	128	6	831
22	Choteau	1,684	868	171	3	1,042
23	Churchill	902	454	51	-	505
24	Clancy	1,661	696	32	-	728
25	Clinton	1,052	370	18	1	389
26	Columbia Falls	4,688	3,335	367	3	3,705
27	Columbus	1,893	1,074	170	6	1,250
28	Conrad	2,570	1,117	209	13	1,339
29	Coram	539	108	25	-	133
30	Corbin	-	1	-	-	1
31	Corvallis	976	1,158	90	-	1,248
32	Cut Bank	2,869	44	12	1	57
33	Deer Lodge	3,111	1,607	209	5	1,821
34	Dillon	4,134	2,067	338	5	2,410
35	Drummond	309	205	51	2	258
36	East Glacier Park	363	128	47	1	176
37	East Helena	1,984	1,965	116	2	2,083
38	Elliston	219	96	13	-	109
39	Essex	-	79	18	1	98
40	Fairfield	708	402	86	4	492
41	Florence	765	1,209	76	1	1,286
42	Floweree	-	39	7	-	46
43	Fort Belknap	1,293	349	58	-	407
44	Fort Benton	1,464	637	156	-	793
45	Fort Harrison	-	-	8	61	69
46	Fort Shaw	280	107	11	-	118
47	Galata	-	3	-	-	3
48	Gallatin Gateway	856	167	39	-	206
49	Garneill	-	7	1	-	8
50	Garrison	96	20	6	-	26
51	Gildford	179	77	25	-	102
52	Grantsdale	-	23	2	-	25
53	Great Falls	58,505	974	49	4	1,027

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Greycliff	112	44	6	-	50
2	Hall	-	60	11	-	71
3	Hamilton	4,348	3,944	703	7	4,654
4	Harlem	808	314	64	2	380
5	Harlowton	997	526	96	2	624
6	Havre	10,026	4,519	646	9	5,174
7	Helena	53,457	18,058	2,406	27	20,491
8	Hingham	118	83	31	-	114
9	Hungry Horse	826	228	35	-	263
10	Inverness	55	36	13	-	49
11	Jefferson City	472	162	13	2	177
12	Joplin	157	93	24	-	117
13	Judith Gap	126	70	15	-	85
14	Kalispell	19,927	11,775	2,019	16	13,810
15	Kremlin	98	46	16	-	62
16	Laurel	6,718	11	1	-	12
17	Ledger	-	7	-	-	7
18	Lewistown	5,901	2,943	493	10	3,446
19	Livingston	7,044	3,993	564	14	4,571
20	Logan	99	40	6	-	46
21	Lohman	-	2	1	-	3
22	Lolo	3,892	1,629	96	-	1,725
23	Loma	85	42	19	-	61
24	Manhattan	1,520	741	103	1	845
25	Martin City	500	117	15	-	132
26	Marysville	80	1	-	-	1
27	Milltown	-	73	9	-	82
28	Missoula	66,788	29,880	3,790	45	33,715
29	Montana City	2,715	750	66	-	816
30	Moore	193	3	-	-	3
31	Philipsburg	820	415	87	-	502
32	Power	-	-	1	-	1
33	Ramsay	-	40	7	-	47
34	Red Lodge	2,125	1,851	289	7	2,147
35	Reedpoint	193	114	14	1	129
36	Roberts	361	163	20	-	183
37	Rocker	-	41	6	-	47
38	Rudyard	258	132	26	-	158
39	Ryegate	245	3	1	-	4
40	Shawmut	42	24	4	-	28
41	Shelby	3,376	9	3	-	12
42	Sheridan	642	417	74	-	491
43	Silver Star	-	19	3	-	22
44	Silverbow	-	3	1	2	6
45	Simms	354	159	17	-	176
46	Somers	1,109	385	20	-	405
47	Springdale	42	1	-	-	1
48	Stevensville	1,809	1,599	244	5	1,848
49	Sun River	124	105	16	-	121
50	Three Forks	1,869	807	127	1	935
51	Turah	306	118	3	-	121
52	Twin Bridges	375	204	59	-	263

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Valier	509	312	71	4	387
2	Vaughn	658	333	23	1	357
3	Victor	745	475	73	1	549
4	Walkerville	675	233	11	-	244
5	Warm Springs	-	13	1	-	14
6	West Glacier	227	105	42	3	150
7	Whitefish	6,357	4,047	492	4	4,543
8	Whitehall	1,038	681	107	2	790
9	Whitlash	-	2	3	-	5
10	Williamsburg	-	1	-	-	1
11	Willow Creek	210	94	12	-	106
12	Wolf Creek	-	49	28	-	77
13						
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47						
48	**Total**	512,464	160,511	22,521	357	183,389

1/ Customer populations represent an average of the 12 month period from 01/01/13 through 12/31/13.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	106	108	107
5	Finance	128	128	128
6	Regulatory Affairs	29	29	29
7	Distribution	583	528	556
8	Transmission	197	279	238
9	Supply	31	40	36
10	Legal	16	19	18
11				
12				
13				
14				
15				
16				
17				
18	**TOTAL EMPLOYEES**	1,092	1,133	1,113

1/ Consistent with prior years, part time employees have been converted to full-time equivalents.

Sch. 31	MONTANA CONSTRUCTION BUDGET 2014 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Elec Trans - Amps Line Upgrade	$9,815,703	$9,815,703
4	MT Elec Trans - Jack-Rabbit-Big Sky 161kV Line	9,479,595	9,479,595
5	MT Elec Trans - NERC Facilities Compliance Clearances 230/161	6,119,421	6,119,421
6	MT Elec Trans - Millcreek 161KV Breaker Ring Bus Addition	3,911,374	3,911,374
7	MT Elec Trans - Columbus-Chrome100KV line	2,812,916	2,812,916
8	MT Elec Trans - Crooked Falls Switchyard Expansion	2,619,168	2,619,168
9	MT Elec Trans - Dillon-Salmon 161-69 Auto Bank upgrade	1,996,939	1,996,939
10	MT Elec Trans - Hot Springs-Anaconda 230kv CSKT permit renew	1,590,225	1,590,225
11	MT Elec Distribution - YNP Communication Infrastructure	3,875,959	3,875,959
12	MT Elec Distribution - Elec Distribution Infrastructure Plan	44,872,489	44,872,489
13	MT Elec Distribution - Billings 8th Street Sub Ringbus	2,903,195	2,903,195
14	MT Elec Distribution - Livingston City Sub	1,655,167	1,655,167
15	SD Elec Trans - Yankton East 115KV Trans Source	5,679,170	
16			
17			
18	All Other Projects < $1 Million Each MT	48,434,302	48,434,302
19	All Other Projects < $1 Million Each SD	17,092,641	
20	**Total Electric Utility Construction Budget**	162,858,263	140,086,452
21			
22	**Natural Gas Operations**		
23	MT Gas Retail - Gas Distribution Infrastructure Plan	7,022,802	7,022,802
24	MT Gas Trans - GTIP Bozeman East Reroute and USM living	3,702,263	3,702,263
25	MT Gas Trans - GTIP Missoula Ben Hogan Drive reroute	1,495,983	1,495,983
26	MT Gas Trans - Gas Trans Rock Creek exposure	1,173,201	1,173,201
27	All Other Projects < $1 Million Each MT	14,317,716	14,317,716
28	All Other Projects < $1 Million Each SD NE	4,322,456	
29	**Total Natural Gas Utility Construction Budget**	32,034,421	27,711,965
30			
31	**Common**		
32	Fleet and Equipment Purchases	6,500,000	4,392,000
33	14 FMS MT NEW GO BUILDING	8,857,308	8,857,308
34			
35	All Other Projects < $1 Million Each MT	8,272,444	8,272,444
36	(Includes IT, Communications, Facilities, Cust Serv)		
37	All Other Projects < $1 Million Each SD NE	2,721,209	
38			
39	**Total Common Utility Construction Budget**	26,350,961	21,521,752
40			
41	MT CU4 capital additions - PPL invoice	7,137,000	7,137,000
42	MT - Gas Prodcution	750,000	750,000
43	SD Big Stone, Neal 4, Coyote partner capital	3,543,239	
44	SD Generation - Big Stone and Neal environmental upgrades	37,875,499	
45			
46	All Other Projects < $1 Million Each MT	1,270,377	1,270,377
47	All Other Projects < $1 Million Each SD		
48	**Total MT/SD Generation**	50,576,115	9,157,377
49	TOTAL CONSTRUCTION BUDGET	$271,819,760	$198,477,546

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	Montana
1	January						5,717,905
2	February						4,519,824
3	March						4,493,711
4	April		NOT AVAILABLE 1/				3,420,152
5	May						2,245,820
6	June						1,990,895
7	July						1,810,318
8	August						1,897,743
9	September						2,209,136
10	October						3,609,443
11	November						4,614,016
12	December						6,142,458
13	TOTAL						42,671,421
14							
15							

16	**Distribution System-Sales and Transportation**						
17		Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
18	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
19	January		3,210,264		10,978		3,221,242
20	February		2,787,666		17,840		2,805,506
21	March		2,380,367		6,715		2,387,082
22	April		1,804,943		3,719		1,808,662
23	May		1,349,223		3,970		1,353,193
24	June		742,367		1,537		743,904
25	July		520,330		1,593		521,923
26	August		390,581		1,475		392,056
27	September		418,450		1,795		420,245
28	October		1,019,796		2,148		1,021,944
29	November		1,745,468		4,043		1,749,511
30	December		2,914,118		6,770		2,920,888
31	TOTAL		19,283,573		62,583		19,346,156
32							
33							

34	**Storage System-Sales and Transportation**						
35		Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
36		Total Company	Montana	Total Montana		Energy Supply	
37	Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
38	January			1,661	3,594,856		1,952,293
39	February			2,360	2,396,136		1,402,830
40	March			78,088	1,731,918		863,634
41	April			213,890	1,028,451		471,171
42	May			1,388,417	86,073	1,164,789	
43	June			1,747,530	23,178	1,324,077	
44	July			2,105,676	28,586	1,757,610	
45	August			2,088,519	153,731	1,742,952	
46	September			1,906,153	139,513	1,338,276	
47	October			845,672	251,024	279,066	
48	November			50,295	2,055,552		1,394,437
49	December			17,860	3,335,067		1,839,427
50	TOTAL			10,446,121	14,824,085	7,606,770	7,923,792

51

52 1/ Data is not accumulated on a daily basis, therefore the peak day and peak day volumes are not available.

53

54

55

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	4,937,212		$6.2040	
3	Havre Pipeline	6,183,377		2.3523	
4	Encana Pipeline	5,569,658		2.2917	
5	Intra Montana Purchase	1,072,533		2.3156	
6	**TOTAL CORE SUPPLY LAST YEAR**	17,762,780		$3.2817	
7					
8	Canadian Pipeline		6,038,000		$4.0230
9	Havre Pipeline		6,331,850		3.0240
10	Encana Pipeline		4,638,292		2.9860
11	Intra Montana Purchase		1,056,614		3.0060
12	**TOTAL CORE SUPPLY THIS YEAR**		18,064,756		$3.1687
13					
14	Note: This schedule does not include company owned production.				
15					
16					

Sch. 34	MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS						
	Program Description (These are Gas DSM Programs)	Current Year Expenditures	Previous Year Expenditures	% Change	Planned Savings (Mcf or Dkt)	Achieved Savings (Mcf or Dkt)	Difference
1							
2	2013 E+ Natural Gas Residential Existing Program	$ 623,354	$ 908,234	-31.37%	74,203	26,704	(47,499)
3							
4	2013 E+ Business Partners Program (Gas)	$ 42,409	$ 256,498	-83.47%	4,385	1,578	(2,807)
5							
6	2013 E+ Natural Gas Residential New Construction Program	$ 14,520	$ 34,726	-58.19%	814	293	(521)
7							
8	2013 E+ Natural Gas Commercial Existing Program	$ 194,635	$ 269,044	-27.66%	22,178	7,981	(14,196)
9							
10	2013 E+ Natural Gas Commercial New Construction Program	$ 33,447	$ 31,963	4.64%	5,583	2,009	(3,574)
11							
12	2013 Northwest Energy Efficiency Alliance (NEEA)*	$ 1,812,164	$ 1,460,604	24.07%	24,960	8,983	(15,977)
13							
14	2013 E+ Natural Gas Building Blocks Program	($50)	$50	-200.00%	0	0	0
15							
16							
17							
18							
19							
20							
21	A program participant is a Montana residential and/or						
22	commercial natural gas customer who installs eligible						
23	energy conservation measures and receives financial						
24	incentives/rebates.						
25							
26	*Note: NEEA expeditures are the full 2013 NEEA costs, costs are						
27	not allocated by gas and electric savings amounts.						
28							
29							
30							
31							
32	TOTAL	$ 2,720,479	$ 2,961,119	-8.13%	132,122	47,548	(84,574)

Sch. 35	MONTANA CONSUMPTION AND REVENUES - NATURAL GAS						
		Operating Revenues 1/		Dkt Sold 1/		Average Customers	
	Description	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Sales of Natural Gas						
2							
3	Residential	$ 111,697,080	$ 102,161,589	12,736,227	11,826,148	160,511	159,437
4	Commercial	56,412,993	51,616,810	6,590,792	6,082,118	22,457	22,330
5	Industrial Firm	1,083,842	1,012,511	129,177	121,657	265	271
6	Public Authorities	513,312	460,505	62,414	55,235	92	93
7	Interdepartmental	507,287	438,189	62,556	53,474	64	57
8	Sales to Other Utilities 2/	1,170,507	1,131,234	211,749	197,544	4	4
9	TOTAL SALES	$ 171,385,021	$ 156,820,838	19,792,915	18,336,176	183,393	182,192
10		Operating Revenues		Dkt Transported		Average Customers	
11		Current	Previous	Current	Previous	Current	Previous
12		Year	Year	Year	Year	Year	Year
13	Transportation of Gas						
14							
15	On System Transportation	$ 23,205,120	$ 21,154,345	22,570,758	22,424,620	252	253
16	Off System Transportation & Storage	10,237	7,213	188,917	109,154	3	3
17	Canadian Montana Pipeline	145,640	127,772				
18	TOTAL TRANSPORTATION	$ 23,360,997	$ 21,289,330	22,759,675	22,533,774	255	256

30 1/ Revenue and Dkts include unbilled and Canadian Montana Pipeline.

32 2/ Includes Sales to Other Utilities only, as compared to Schedule 9 which includes all Sales for Resale.

Sch. 36a	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	$ 900,000	$ -	$ 900,000	13,010	2012
3	NWE Promotion	60,296	-	60,296		
4	NWE Labor	21,476	-	21,476		
5	NWE Admin. Non-labor	7,156	-	7,156		
6	USB Interest & Svc Chg	(145)	-	(145)		
7	Low Income					
8	Bill Assistance	1,145,932	-	1,145,932		
9	Free Weatherization	1,393,000	-	1,393,000	13,818	2012
10	Energy Share	336,000	-	336,000		
11	NWE Promotion	1,675	-	1,675		
12	NWE Labor	42,557	-	42,557		
13	NWE Admin. Non-labor	510	-	510		
14	USB Interest & Svc Chg	(471)	-	(471)		
15	Total	$ 3,907,987	$ -	$ 3,907,987	26,828	
16	Number of customers that received low income rate discounts				8,002	
17	Average monthly bill discount amount ($/mo)				$ 23.87	*(a)*
18	Average LIEAP-eligible household income				n/a	
19	Number of customers that received weatherization assistance				427	*(b)*
20	Expected average annual bill savings from weatherization				32	Dkt
21	Number of residential audits performed				4,775	*(b)*
22	(a) Average monthly bill discount is for the six (6) month time period that the natural gas rate discount is in effect.					
26	(b) Total savings and number of customers is reported for the combination of 2013 electric and natural gas USB funds expended in 2013.					
24	*Note: Order 6679e, allows NWE to track on an annual basis its Natural Gas USB expenditures and revenues and adjust the Natural Gas USB Charge for any over or under collections.*					

Sch. 36b	Montana Conservation & Demand Side Management Programs					
	Program Description (These are Gas USB Programs)	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+ Energy Audit for the Home (Natural Gas)	$ 900,000	$ -	$ 900,000	13,010	2012
3						
4	Market Transformation					
5	Building Operator Certification	$ -	$ -	$ -	1,199	2012
6						
7	Low Income					
8	Free Weatherization (Natural Gas)	$ 1,393,000	$ -	$ 1,393,000	13,818	2012
9						
10	Total	$ 2,293,000	$ -	$ 2,293,000	28,027	