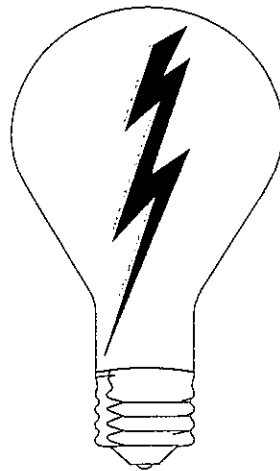


YEAR ENDING 2014

ANNUAL REPORT  
OF

NorthWestern Energy

ELECTRIC UTILITY



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

# Electric Annual Report

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Sch. 1	IDENTIFICATION	
1		
2	Legal Name of Respondent:	NorthWestern Corporation
3		
4	Name Under Which Respondent Does Business:	NorthWestern Energy
5		
6	Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912
7		Natural Gas - Jan 01, 1933
8		Propane - Oct 13, 1995
9		
10	Person Responsible for Report:	Kendall G. Kliever
11		
12	Telephone Number for Report Inquiries:	(406) 497-2759
13		
14	Address for Correspondence Concerning Report:	40 East Broadway Street
15		Butte, MT 59701
16		
17		
18	<p>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:</p> <p>N/A</p>	

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See Northwestern Corporation's Annual Report on Form 10-K to the SEC for the Corporate Board of Directors.	
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
1	President & Chief Executive Officer	Executive	Robert Rowe
2			
3			
4			
5	Vice President, Chief Financial Officer	Tax, Internal Audit, Credit	Brian Bird
6		Financial Planning and Analysis	
7		Controller and Treasury Functions	
8		Investor Relations and Corporate Finance	
9		Cash Management and Business Technology	
10		Energy Risk Management	
11		Flight Services, Executive Compensation	
12	Vice President, General Counsel	Legal Services	Heather Grahame
13		Corporate Secretary & Shareholder Services	
14		Records Management	
15		Risk Management	
16		FERC Compliance	
17			
18	Vice President, Distribution Operations	Distribution Operations - MT/SD/NE	Curt Pohl
19		Construction, Asset Management	
20		Organizational Development & Labor Relations	
21		Project Management	
22		Safety/Health/Environmental Services	
23		Support Services	
24	Vice President, Transmission	Electric Transmission, Engineering & Planning	Michael Cashell
25		Gas Transmission & Storage	
26		Grid & Substation Operations	
27		Transmission Business Development and Analysis	
28		Transmission & Distribution Organizational Performance	
29			
30	Vice President, Supply	Production & Generation Operations	John Hines
31		Energy Supply Planning, Regulatory, &	
32		Marketing	
33		Energy Supply Long-Term Resources	
34	Vice President, Government & Regulatory Affairs	Government & Regulatory Affairs	Patrick Corcoran
35			
36			
37	Vice President, Customer Care, Communications & Human Resources	Corporate Communications	Bobbi Schroeppel
38		Account and Analysis	
39		Infrastructure Systems and Support	
40		Customer Care	
41		Key Accounts/Customer Interaction	
42		Revenue Cycle Management	
43		Human Resources	
44	Chief Audit & Compliance Officer	Internal Audit	Michael Nieman
45		Enterprise Risk	
46			
47	Vice President, Controller	Financial Reporting	Kendall Kliewer
48		Accounting	
49		Accounts Payable/Payroll	
50		Compensation and Benefits	
51			
52			
53			
54			
55			
56			
	Reflects active officers as of December 31, 2014.		

Sch. 4	CORPORATE STRUCTURE			
Subsidiary/Company Name		Line of Business	Earnings (000)	% of Total
Regulated Operations (Jurisdictional & Non-Jurisdictional)			\$ 117,669	97.50%
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			\$ 3,017	2.50%
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			\$ 120,686	100.00%

Sch. 5	CORPORATE ALLOCATIONS					
	Departments Allocated	Description of Services	Allocation Method	\$ to MT EI & Gas Utilities	MT %	\$ to Other
1	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.	\$15,201,076	74.01%	\$5,338,153
2						
3						
4						
5	Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Corp Communications & Contributions, CC - Assoc & Dispatch 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.	24,138,886	73.99%	8,487,106
6						
7						
8						
9	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.	11,193,990	80.84%	2,652,477
10						
11						
12						
13	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.	15,863,291	74.01%	5,571,422
14						
15						
16						
17	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.	4,029,507	81.03%	943,529
18						
19						
20						
21	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.	2,719,342	71.82%	1,067,163
22						
23						
24						
25	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.	788,978	73.00%	291,813
26						
27						
28						
29	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.	507,309	73.00%	187,635
30						
31						
32						
33	Hydro Administration	Includes Hydro Administration Exp from the following departments: Marketing Supply Operation, Safety, Customer Care, Telecom Networking Legal, Risk Management, Communications & HR, Business Technology	Overhead costs charged directly.	453,905	100.00%	0
34						
35						
36						
37	TOTAL			\$74,896,284	75.32%	\$24,539,298
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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	Nonutility Subsidiaries					
2						
3						
4						
4	Total Nonutility Subsidiaries			\$0		\$0
5	Total Nonutility Subsidiaries Revenues			\$0		
6						
7						
8	Utility Subsidiaries					
9						
10						
11						
11	Total Utility Subsidiaries			\$0		\$0
12	Canadian-Montana Pipeline Corporation	Natural gas pipeline	Contract rate	\$145,443		
13	Havre Pipeline Company, LLC	Natural gas gathering	Tariffed rate	5,289,878		
14	Total Utility Subsidiaries Revenues			\$5,435,321		
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	Nonutility Subsidiaries											
2												
3												
4												
5												
6	Total Nonutility Subsidiaries			\$0		\$0						
7	Total Nonutility Subsidiaries Expenses			\$0								
8												
9												
10	Utility Subsidiaries											
11												
12												
13							Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	\$500,400	14.0%	\$500,400
14												
15	Total Utility Subsidiaries			\$500,400		\$500,400						
16	Total Utility Subsidiaries Expenses			\$3,610,287								
17	TOTAL AFFILIATE TRANSACTIONS			\$500,400		\$500,400						

Sch. 8	MONTANA UTILITY INCOME STATEMENT - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	400 Operating Revenues	\$ 916,951,451	\$ 136,273,261	\$ 780,678,190	\$ 765,801,184	1.94%
2						
3						
4	<b>Total Operating Revenues</b>	<b>916,951,451</b>	<b>136,273,261</b>	<b>780,678,190</b>	<b>765,801,184</b>	<b>1.94%</b>
5						
6	<b>Operating Expenses</b>					
7						
8	401 Operation Expenses	543,666,189	80,821,548	462,844,641	461,399,787	0.31%
9	402 Maintenance Expense	51,767,973	9,349,813	42,418,160	39,436,294	7.56%
10	403 Depreciation Expense	97,091,845	17,897,791	79,193,854	76,713,742	3.23%
11	404-405 Amort. of Electric Plant	3,744,600	726,748	3,017,852	2,581,606	16.90%
12	406 Amort. of Plant Acquisition Adj.	(929,096)	(1,866,098)	937,002	-	-
13	407.3 Regulatory Amortizations - Debit	2,200,796	575,455	1,625,341	485,652	234.67%
14	407.4 Regulatory Amortizations - Credit	(15,521,641)	-	(15,521,641)	(5,553,290)	-179.50%
15	408.1 Taxes Other Than Income Taxes	90,381,367	6,192,894	84,188,473	78,050,534	7.86%
16	409.1 Income Taxes - Federal	(4,303,447)	(10,666,765)	6,363,318	3,133,453	103.08%
17	- Other	764,042	(1,162,091)	1,926,133	1,342,867	43.43%
18	410.1 Deferred Income Taxes-Dr.	188,250,842	36,188,506	152,082,336	134,793,842	12.83%
19	411.1 Deferred Income Taxes-Cr.	(186,836,326)	(25,998,746)	(160,837,580)	(128,530,768)	-25.14%
20	411.4 Investment Tax Credit Adj.	(245,173)	(245,173)	-	-	-
21	411.6 Gain from Disposition of Property	-	-	-	-	-
22	411.7 Loss from Disposition of Property	-	-	-	-	-
23	411.8 SO2 Allowances	(40)	(33)	(7)	(5)	-51.51%
24						
25	<b>Total Operating Expenses</b>	<b>770,031,731</b>	<b>111,793,849</b>	<b>658,237,882</b>	<b>663,853,714</b>	<b>-0.85%</b>
26	<b>NET OPERATING INCOME</b>	<b>\$ 146,919,720</b>	<b>\$ 24,479,412</b>	<b>\$ 122,440,308</b>	<b>\$ 101,947,470</b>	<b>20.10%</b>
<p>This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.</p>						

Sch. 9	MONTANA REVENUES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	<b>Sales to Ultimate Consumers</b>					
3						
4	440 Residential	\$ 308,140,752	\$ 50,854,956	\$ 257,285,796	\$ 269,817,879	-4.64%
5	442 Commercial	397,114,669	79,105,309	318,009,360	316,212,056	0.57%
6	Industrial	50,819,280	-	50,819,280	51,807,494	-1.91%
7	444 Public Street, Highway Lighting					
8	& Other Sales to Public Authorities	17,681,990	2,034,292	15,647,698	15,688,002	-0.26%
9	448 Interdepartmental Sales	1,125,772	-	1,125,772	1,133,609	-0.69%
10						
11	<b>Total Sales to Ultimate Consumers</b>	<b>774,882,463</b>	<b>131,994,557</b>	<b>642,887,906</b>	<b>654,659,040</b>	<b>-1.80%</b>
12	447 Sales for Resale	65,512,720	1,588,352	63,924,368	45,871,121	39.36%
13						
14	<b>Total Sales of Electricity</b>	<b>840,395,183</b>	<b>133,582,909</b>	<b>706,812,274</b>	<b>700,530,161</b>	<b>0.90%</b>
15	449.1 Provision for Rate Refunds	1,072,047	-	1,072,047	(5,027,860)	121.32%
16						
17	<b>Total Revenue Net of Rate Refunds</b>	<b>841,467,230</b>	<b>133,582,909</b>	<b>707,884,321</b>	<b>695,502,301</b>	<b>1.78%</b>
18						
19	<b>Other Operating Revenues</b>					
20	450 Forfeited Discounts & Late Pymt Rev	467,533	467,533	-	-	-
21	451 Miscellaneous Service Revenue	186,512	186,512	-	-	-
22	453 Sales of Water & Water Power	570,825	-	570,825	-	-
23	454 Rent From Electric Property	2,913,225	249,759	2,663,466	2,442,668	9.04%
24	456 Other Electric Revenues	71,346,126	1,786,548	69,559,578	67,856,215	2.51%
25						
26	<b>Total Other Operating Revenue</b>	<b>75,484,221</b>	<b>2,690,352</b>	<b>72,793,869</b>	<b>70,298,883</b>	<b>3.55%</b>
27	<b>TOTAL OPERATING REVENUE</b>	<b>\$ 916,951,451</b>	<b>\$ 136,273,261</b>	<b>\$ 780,678,190</b>	<b>\$ 765,801,184</b>	<b>1.94%</b>

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	<b>Power Production Expenses</b>					
2	<b>Steam Power Generation-Operation</b>					
3	500 Supervision & Engineering	\$ 1,120,100	\$ 1,080,043	\$ 40,057	\$ 61,313	-34.67%
4	501 Fuel	54,534,741	29,045,112	25,489,629	22,484,050	13.37%
5	502 Steam Expenses	2,728,252	1,224,463	1,503,789	1,254,347	19.89%
6	503 Steam from Other Sources	-	-	-	-	-
7	505 Electric Plant	842,959	551,598	291,361	247,807	17.58%
8	506 Miscellaneous Steam Power	2,666,706	1,159,254	1,507,451	1,586,809	-5.00%
9	507 Rents	60,227	23,821	36,407	30,075	21.05%
10	<b>Total Operation-Steam Power Gen.</b>	<b>61,952,985</b>	<b>33,084,291</b>	<b>28,868,694</b>	<b>25,664,400</b>	<b>12.49%</b>
11	<b>Steam Power Generation-Maintenance</b>					
12	510 Supervision & Engineering	812,852	402,461	410,391	350,010	17.25%
13	511 Structures	987,530	308,853	678,677	542,216	25.17%
14	512 Steam Boiler Plant	6,279,696	1,966,796	4,312,900	4,009,446	7.57%
15	513 Electric Plant	2,173,230	727,678	1,445,552	927,420	55.87%
16	514 Miscellaneous Steam Plant	1,027,419	425,160	602,259	521,265	15.54%
17	<b>Total Maintenance-Steam Power Gen.</b>	<b>11,280,727</b>	<b>3,830,948</b>	<b>7,449,779</b>	<b>6,350,357</b>	<b>17.31%</b>
18	<b>Total Steam Power Generation</b>	<b>73,233,712</b>	<b>36,915,239</b>	<b>36,318,473</b>	<b>32,014,758</b>	<b>13.44%</b>
19	<b>Hydro Power Generation-Operation</b>					
20	535 Supervision & Engineering	131,681	-	131,681	-	-
21	536 Water for Power	117,070	-	117,070	-	-
22	537 Hydraulic Expenses	427,823	-	427,823	-	-
23	538 Electric Expenses	485,032	-	485,031	-	-
24	539 Miscellaneous Hydraulic Power	134,946	-	134,946	-	-
25	540 Rents	2,912,990	-	2,912,990	-	-
26	<b>Total Operation-Hydro Power Gen.</b>	<b>4,209,542</b>	<b>-</b>	<b>4,209,541</b>	<b>-</b>	<b>-</b>
27	<b>Hydro Power Generation-Maintenance</b>					
28	541 Supervision & Engineering	116,667	-	116,667	-	-
29	542 Structures	18,293	-	18,293	-	-
30	543 Reservoirs, Dams & Waterways	152,003	-	152,003	-	-
31	544 Electric Plant	240,427	-	240,427	-	-
32	545 Miscellaneous Hydro Plant	-	-	-	-	-
33	<b>Total Maintenance-Hydro Power Gen.</b>	<b>527,390</b>	<b>-</b>	<b>527,390</b>	<b>-</b>	<b>-</b>
34	<b>Total Hydraulic Power Generation</b>	<b>4,736,932</b>	<b>-</b>	<b>4,736,931</b>	<b>-</b>	<b>-</b>
35	<b>Other Power Generation-Operation</b>					
36	546 Supervision & Engineering	1,183,770	120,353	1,063,417	1,684,057	-36.85%
37	547 Fuel	23,710,162	957,517	22,752,645	20,346,020	11.83%
38	548 Generation Expenses	3,362,812	753,254	2,609,558	2,334,044	11.80%
39	549 Miscellaneous Other Power	2,802,749	19,288	2,783,461	1,550,342	79.54%
40	550 Rents	-	-	-	15,866	-100.00%
40	<b>Total Operation-Other Power Gen.</b>	<b>31,059,493</b>	<b>1,850,412</b>	<b>29,209,081</b>	<b>25,930,328</b>	<b>12.64%</b>
41	<b>Other Power Generation-Maintenance</b>					
42	551 Supervision & Engineering	109,166	109,166	-	24,533	-100.00%
43	552 Structures	1,290	-	1,290	1,073	20.21%
44	553 Generating & Electric Plant	3,930,325	256,532	3,673,793	412,464	>300.00%
45	554 Miscellaneous Other Power Plant	134,672	684	133,988	19,298	>300.00%
46	<b>Total Maintenance-Other Power Gen.</b>	<b>4,175,453</b>	<b>386,382</b>	<b>3,809,071</b>	<b>457,368</b>	<b>&gt;300.00%</b>
47	<b>Total Other Power Generation</b>	<b>35,234,946</b>	<b>2,216,794</b>	<b>33,018,152</b>	<b>26,387,696</b>	<b>25.13%</b>
48	<b>Other Power Supply Expenses</b>					
49	555 Purchased Power	315,957,355	21,110,291	294,847,064	303,655,162	-2.90%
50	556 System Control & Load Dispatch	151,677	151,677	-	-	-
51	557 Other Expenses	2,674,801	2,176,987	497,814	(69,127)	>300.00%
52	<b>Total Other Power Supply Expenses</b>	<b>318,783,833</b>	<b>23,438,955</b>	<b>295,344,878</b>	<b>303,586,035</b>	<b>-2.71%</b>
53	<b>Total Power Production Expenses</b>	<b>431,989,423</b>	<b>62,570,988</b>	<b>369,418,435</b>	<b>361,988,489</b>	<b>2.05%</b>

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	<b>Transmission Expenses</b>					
3						
4	<b>Transmission-Operation</b>					
5	560 Supervision & Engineering	3,805,005	402,310	3,402,695	3,388,477	0.42%
6	561 Load Dispatching	70,830	70,830	-	-	-
7	561.1 Load Dispatch - Reliability	887,900	-	887,900	1,012,901	-12.34%
8	561.2 Load Disp-Monitor/Op	709,007	105,171	603,836	589,814	2.38%
9	561.3 Load Disp-Srv/Schedu	1,643,151	520,669	1,122,482	1,150,249	-2.41%
10	561.4 Relia Pln/StdDev-RTO	-	-	-	-	-
11	561.5 Reliab, Plan, Stds	88,523	88,523	-	-	-
12	561.6 Transmission Service Studies	-	-	-	-	-
13	561.8 Sch,Sys&Ctrl Srv-RTO	-	-	-	-	-
14	562 Station Expenses	1,474,860	278,010	1,196,850	1,055,319	13.41%
15	563 Overhead Lines	1,257,748	347,230	910,518	1,211,752	-24.86%
16	564 Underground Lines	-	-	-	-	-
17	565 Transmission of Elec. by Others	9,507,010	3,903,378	5,603,632	5,569,060	0.62%
18	566 Miscellaneous Transmission	144,149	130,080	14,069	329,031	-95.72%
19	567 Rents	932,413	4,473	927,940	878,754	5.60%
20	<b>Total Operation-Transmission</b>	<b>20,520,596</b>	<b>5,850,674</b>	<b>14,669,922</b>	<b>15,185,357</b>	<b>-3.39%</b>
21	<b>Transmission-Maintenance</b>					
22	568 Supervision & Engineering	1,728,835	356,289	1,372,546	1,424,192	-3.63%
23	569 Structures	33,551	17,486	16,065	21,100	-23.86%
24	569.1 Maintenance of Computer Hardware	615,764	-	615,764	310,433	98.36%
25	569.2 Maintenance of Computer Software	819,643	-	819,643	1,198,079	-31.59%
26	569.3 Maint-Comm Equip	85,723	85,723	-	-	-
27	570 Station Equipment	1,329,714	365,458	964,256	762,053	26.53%
28	571 Overhead Lines	3,445,355	318,479	3,126,876	2,857,085	9.44%
29	572 Underground Lines	90	90	-	-	-
30	573 Miscellaneous Transmission Plant	-	-	-	-	-
31	<b>Total Maintenance-Transmission</b>	<b>8,058,675</b>	<b>1,143,525</b>	<b>6,915,150</b>	<b>6,572,942</b>	<b>5.21%</b>
32	<b>Total Transmission Expenses</b>	<b>28,579,271</b>	<b>6,994,199</b>	<b>21,585,072</b>	<b>21,758,299</b>	<b>-0.80%</b>
33						
34	<b>Distribution Expenses</b>					
35						
36	<b>Distribution-Operation</b>					
37	580 Supervision & Engineering	4,650,938	1,066,060	3,584,878	3,461,912	3.55%
38	581 Load Dispatching	-	-	-	-	-
39	582 Station Expenses	2,539,127	383,292	2,155,835	2,021,516	6.64%
40	583 Overhead Lines	4,064,552	440,321	3,624,231	4,011,122	-9.65%
41	584 Underground Lines	2,589,191	909,736	1,679,455	1,749,201	-3.99%
42	585 Street Lighting & Signal Systems	910,091	37,447	872,644	919,297	-5.07%
43	586 Meters	3,594,559	658,765	2,935,794	3,050,661	-3.77%
44	587 Customer Installations	2,718,235	308,436	2,409,799	2,002,888	20.32%
45	588 Miscellaneous Distribution	4,654,700	539,609	4,115,091	4,181,851	-1.60%
46	589 Rents	58,341	-	58,341	82,921	-29.64%
47	<b>Total Operation-Distribution</b>	<b>25,779,734</b>	<b>4,343,666</b>	<b>21,436,068</b>	<b>21,481,369</b>	<b>-0.21%</b>
48	<b>Distribution-Maintenance</b>					
49	590 Supervision & Engineering	2,563,294	720,664	1,842,630	1,827,365	0.84%
50	591 Structures	31,175	-	31,175	36,929	-15.58%
51	592 Station Equipment	1,473,751	431,635	1,042,116	1,464,689	-28.85%
52	593 Overhead Lines	15,664,140	2,111,947	13,552,193	15,497,505	-12.55%
53	594 Underground Lines	1,975,992	264,638	1,711,354	1,857,246	-7.86%
54	595 Line Transformers	197,196	30,856	166,340	201,010	-17.25%
55	596 Street Lighting, Signal Systems	1,144,616	139,031	1,005,585	921,190	9.16%
56	597 Meters	1,492,975	67,657	1,425,318	1,318,599	8.09%
57	598 Miscellaneous Distribution Plant	37,447	37,447	-	-	-
58	<b>Total Maintenance-Distribution</b>	<b>24,580,586</b>	<b>3,803,875</b>	<b>20,776,712</b>	<b>23,124,533</b>	<b>-10.15%</b>
59	<b>Total Distribution Expenses</b>	<b>50,360,320</b>	<b>8,147,541</b>	<b>42,212,780</b>	<b>44,605,902</b>	<b>-5.37%</b>

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	<b>Customer Accounts Expenses</b>					
3						
4	<b>Customer Accounts-Operation</b>					
5	901 Supervision	-	-	-	-	-
6	902 Meter Reading	2,517,282	798,977	1,718,304	1,605,833	7.00%
7	903 Customer Records & Collection	7,624,112	1,348,568	6,275,544	5,859,597	7.10%
8	904 Uncollectible Accounts	2,520,574	353,846	2,166,728	2,398,324	-9.66%
9	905 Miscellaneous Customer Accts.	43,867	44,243	(375)	(116)	-224.38%
10	<b>Total Customer Accounts Expenses</b>	<b>12,705,835</b>	<b>2,545,634</b>	<b>10,160,201</b>	<b>9,863,638</b>	<b>3.01%</b>
11						
12	<b>Customer Service &amp; Information</b>					
13						
14	<b>Customer Service-Operation</b>					
15	907 Supervision	-	-	-	-	-
16	908 Customer Assistance	4,722,059	1,443,983	3,278,076	3,311,211	-1.00%
17	909 Inform. & Instruct. Advertising	848,393	150,934	697,459	697,172	0.04%
18	910 Misc. Customer Service & Info.	829,161	-	829,161	805,417	2.95%
19	<b>Total Customer Service &amp; Info. Expense</b>	<b>6,399,613</b>	<b>1,594,918</b>	<b>4,804,696</b>	<b>4,813,800</b>	<b>-0.19%</b>
20						
21	<b>Sales Expenses</b>					
22						
23	<b>Sales-Operation</b>					
24	911 Supervision	-	-	-	-	-
25	912 Demonstrating & Selling	-	-	-	-	-
26	913 Advertising	614,939	101,709	513,230	440,900	16.41%
27	916 Miscellaneous Sales	-	-	-	-	-
28	<b>Total Sales Expenses</b>	<b>614,939</b>	<b>101,709</b>	<b>513,230</b>	<b>440,900</b>	<b>16.41%</b>
29						
30	<b>Administrative &amp; General Expenses</b>					
31						
32	<b>Admin. &amp; General-Operation</b>					
33	920 Admin. & General Salaries	30,099,702	4,538,247	25,561,455	23,764,397	7.56%
34	921 Office Supplies & Expenses	10,163,723	2,422,302	7,741,420	7,065,438	9.57%
35	922 Admin. Expense Transferred-Cr.	(5,739,411)	(1,928,385)	(3,811,026)	(3,663,655)	-4.02%
36	923 Outside Services Employed	5,864,173	955,071	4,909,102	3,833,328	28.06%
37	924 Property Insurance	1,691,018	384,879	1,306,139	1,105,765	18.12%
38	925 Injuries & Damages	5,469,444	828,774	4,640,670	4,634,109	0.14%
39	926 Employee Pensions & Benefits	(2,096,434)	(267,158)	(1,829,276)	3,403,913	-153.74%
40	927 Franchise Requirements	-	-	-	-	-
41	928 Regulatory Commission Expenses	1,357,262	10,025	1,347,237	818,385	64.62%
42	929 Duplicate Charges-Cr.	-	-	-	-	-
43	930 Miscellaneous General Expenses	12,535,781	606,687	11,929,094	11,804,502	1.06%
44	931 Rents	2,294,361	460,849	1,833,512	1,667,778	9.94%
45	<b>Total Operation-Admin. &amp; General</b>	<b>61,639,619</b>	<b>8,011,291</b>	<b>53,628,328</b>	<b>54,433,959</b>	<b>-1.48%</b>
46	<b>Admin. &amp; General-Maintenance</b>					
47	935 General Plant	3,145,142	205,083	2,940,059	2,931,095	0.31%
48	<b>Total Maintenance-Admin. &amp; General</b>	<b>3,145,142</b>	<b>205,083</b>	<b>2,940,059</b>	<b>2,931,095</b>	<b>0.31%</b>
49	<b>Total Admin. &amp; General Expenses</b>	<b>64,784,761</b>	<b>8,216,374</b>	<b>56,568,387</b>	<b>57,365,055</b>	<b>-1.39%</b>
50	<b>TOTAL OPER. &amp; MAINT. EXPENSES</b>	<b>\$ 595,434,162</b>	<b>\$ 90,171,361</b>	<b>\$ 505,262,801</b>	<b>\$ 500,836,081</b>	<b>0.88%</b>

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	\$4,462,619	\$4,133,570	7.96%
3	Property Taxes	75,068,049	69,770,989	7.59%
4	Electric Energy License Tax	590,175	433,452	36.16%
5	Crow Tribe RR and Utility Tax	41,074	38,028	8.01%
6	City Tax	9,007	7,869	14.47%
7	Consumer Counsel Tax	639,211	431,085	48.28%
8	Public Service Commission Tax	1,884,505	1,634,075	15.33%
9	Heavy Highway Use Tax	13,640	17,911	-23.85%
10	Vehicle Use Tax	165,687	162,753	1.80%
11	Wholesale Energy Transaction Tax	1,210,077	1,317,509	-8.15%
12	Delaware Franchise Tax	104,429	103,294	1.10%
13				
14				
15				
16				
17	<b>TOTAL TAXES OTHER THAN INCOME</b>	<b>\$84,188,473</b>	<b>\$78,050,534</b>	<b>7.86%</b>
18				
19				



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	181,135
2	A EXCAVATION	Excavation Contractor	168,060
3	ALME CONSTRUCTION, INC	Construction	107,573
4	ALSTOM GRID INC	Software Support Services	1,404,560
5	AMERICAN INNOVATIONS INC	Software Support Services	289,429
6	ARCADIS US INC	Engineering Services	1,731,423
7	ASCEND ANALYTICS LLC	Hydro Expert Analysis	473,572
8	ASPEN CONSULTING & TESTING INC	Environmental Consultants	94,588
9	ASPLUNDH TREE EXPERT CO	Tree Trimming	5,052,382
10	ASSOCIATED ARBORISTS	Vegetation Management	2,080,079
11	AUTOMOTIVE RENTALS INC	Fleet Management	8,546,929
12	BART ENGINEERING COMPANY	Engineering Services	522,210
13	BIG COUNTRY ENERGY SERVICES LLC	Construction	583,565
14	BIG SKY WATER HAULING LLC	Water Hauling Services	77,217
15	BILL FIELD TRUCKING INC	Hauling Services	441,718
16	BLANKENHEIM SERVICES LLC	Job Description Writeups	104,716
17	BOBCAT CONSTRUCTION ETC	Fencing Installation	103,248
18	BOZEMAN GREEN BUILD	Solar System Installation	81,160
19	BRINK CONSTRUCTION INC	Construction	263,063
20	BROWNING, KALECZYC, BERRY & HOVAN	Legal Services	94,151
21	C A ADVANCED INC	Construction	1,043,043
22	CB&I STONE & WEBSTER INC	Big Bird Siting and Hydro Studies	296,644
23	CENTRAL AIR SERVICE INC	Aerial Pilot Services	192,735
24	CENTRAL COPTERS INC	Flight Services	203,044
25	CENTRON SERVICES INC	Customer Collection Service	90,689
26	CENTURYLINK ASSET ACCOUNTING	Construction	108,195
27	CESSNA AIRCRAFT COMPANY	Aircraft Maintenance	307,931
28	CLEAN SLATE GROUP	Hydro Signage Services	135,375
29	COMPLETE CAREER CENTER INC	Temporary Employment Services	116,870
30	COMPUTER CONSULTING CORPORATION	Data processing Services	85,125
31	CONTINENTAL STEEL WORKS	Fabrication Services	880,201
32	CORPORATE EXECUTIVE BOARD	Organizational Development Consultant	95,241
33	CRIST, KROGH, BUTLER & NORD LLC	Legal Services	209,121
34	CTA ARCHITECTS ENGINEERS	Energy Conservation Consultants	191,653
35	DAKOTA HIGH VOLTAGE TESTING	Electric System Testing and Maintenance	83,942
36	DAVEY TREE SURGERY COMPANY	Tree Trimming	1,971,532
37	DELL SOFTWARE INC	Software Consultants	121,577
38	DELOITTE & TOUCHE LLP	Audit Services	1,481,970
39	DELOITTE TAX LLP	Tax Services	408,774
40	DEMAND ENERGY NETWORKS INC	Software Support Services	99,872
41	DEPT OF HEALTH & HUMAN SERVICES	Weatherization Program Services	2,220,808
42	DGR ENGINEERING	Engineering Services	883,314
43	DHC INC	Boring Services	97,625
44	DICK ANDERSON CONSTRUCTION INC	Construction	359,911
45	DISTRIBUTION CONSTRUCTION CO	Gas Pipeline Construction	581,781
46	DJ&A P C CONSULTING ENGINEERS	Engineer Professional Services	83,012
47	DOLPHIN ENTERPRISE SOLUTIONS	Computer Licensing	132,894
48	DORSEY & WHITNEY LLP	Legal Services	876,521
49	EAGLE GAS MARKETING LLC	Marketing Services	1,093,744
50	EAGLE LANDSCAPING	Landscape Services	130,437
51	EDM INTERNATIONAL INC	Anchor Rod Inspection Services	236,977
52	ELM LOCATING & UTILITY SERVICE	Locating Services and Excavation Notifications	2,495,152
53	ENERGY SHARE OF MONTANA	USBC Services	855,177
54	FAIRBANKS MORSE ENGINE	Construction	108,627
55	FISHNET SECURITY INC	Software Support Services	1,363,345
56	FLUID MARKET STRATEGIES	Energy Conservation Consultants	610,479
57	FLYNN WRIGHT INC	Advertising Services	1,757,125
58	FORBES TATE LLC	Regulatory Consultants	130,000
59	GARTNER INC	Information Technology Consulting	131,975
60	GARY INCE CONSTRUCTION INC	Construction	153,164

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
61	GE BETZ INC	Chemical Mgt Services	98,197
62	GEODIGITAL INTERNATIONAL CORP	NERC Facility Services	388,594
63	GILLESPIE PRUDHON & ASSOCIATES	Telecommunications Engineers	83,781
64	H & H ASPHALT & MAINTENANCE INC	Asphalt Services	210,533
65	H & H CONTRACTING INC	Concrete and Asphalt Services	654,528
66	HAIDER CONSTRUCTION INC	Backhoe Services	421,651
67	HDR ENGINEERING INC	Engineering Services	884,126
68	HEALTH FITNESS CORPORATION	Employee Wellness Program Management	350,102
69	HEATH CONSULTANTS INC	Gas Leak Surveys	505,766
70	HIGH MARK MEDIA	Marketing Services	140,290
71	HOWALT MCDOWELL INSURANCE INC	Benefits Consultants	108,381
72	HYDRO TECH USA INC	Black Eagle Overhaul	128,100
73	INTEC SERVICES INC	Pole Inspection	476,421
74	INTERGRAPH CORPORATION	Software Consultants	433,019
75	INTERSTATE POWER SYSTEMS INC	Vehicle Repair	93,183
76	IRON PINE COMPANY LLC	Vegetation Management	128,243
77	J&J EXCAVATING & TRUCKING INC	Excavation Services	1,810,525
78	JACOBSEN TREE EXPERTS	Tree Trimming	752,426
79	JARES FENCE COMPANY INC	Fencing Installation	107,075
80	JD ENGINEERING P C	Engineering Services	304,026
81	JONES CONSTRUCTION	Construction	152,407
82	JONES DAY	Legal Services	124,794
83	JORDAN CONTRACTING INC	Construction	101,967
84	JSSI JET SUPPORT SERVICES INC	Flight Services	195,992
85	KC HARVEY ENVIRONMENTAL LLC	Environmental Consultants	318,916
86	KM CONSTRUCTION CO INC	Construction	140,467
87	KNIFE RIVER	Construction	124,047
88	KOERNER CONSTRUCTION	Construction	218,337
89	LANDS ENERGY CONSULTING	Energy Consultants	124,236
90	LARSON DIGGING INC	Excavation Services	121,157
91	LAST BEST PLACE LANDSCAPING INC	Landscape Services	104,614
92	LOCKMER PLUMBING HEATING & UTILITIES	Gas Meter Relocations	155,925
93	M&P EXCAVATING LLP	Excavation Services	242,470
94	MANAGEMENT APPLICATIONS CONSULTING	Regulatory Consultants	208,926
95	MAPPCOR	Electric Reliability Services	436,406
96	MARKOVICH CONSTRUCTION INC	Construction	307,345
97	MCKINSTRY ESSENTION	Energy Conservation Consultants	103,185
98	MERCER HUMAN RESOURCE CONSULTI	HR Consulting	75,906
99	MERIDIAN IT INC	Information Technology Services	1,187,702
100	MICROSOFT LICENSING GP	Computer Licensing	851,273
101	MICROSOFT SERVICES	Computer Maintenance	113,123
102	MOODY'S INVESTORS SERVICE	Debt Rating Services	247,500
103	MORRISON MAIERLE INC	Engineering Services	262,758
104	MOSAIC ARCHITECTURE	Architects	579,723
105	MOUNTAIN POWER CONSTRUCTION CO	Construction	15,635,673
106	MOUNTAIN WEST HOLDING COMPANY	Construction	426,518
107	MUTH ELECTRIC INC	Transformer Installation	149,828
108	NAT'L CENTER FOR APPROPRIATE TECHNOLOGY	Conservation Program Consultants	697,948
109	NAVIGANT CONSULTING INC	Transmission System Consultants	233,617
110	NETMOTION WIRELESS INC	Software Maintenance	154,680
111	NEXANT INC	Energy Efficiency Consultants	83,998
112	NORLEY CONSULTING	Gas Compressor Consultant	150,334
113	NORTHWEST DYNAMICS INSPECTION	Safety Inspections	81,039
114	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,086,495
119	OLSON LAND SERVICES	Real Estate Services	86,053
120	OMIMEX CANADA LTD	Gas Lease Operating Expenses	1,537,598
121	OPEN ACCESS TECHNOLOGY INT'L INC	Software Support Services	402,170
122	OSMOSE INC	Construction	2,329,206
123	P2 ENERGY SOLUTIONS INC	Computer System Implementation	223,680
124	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	18,493,725
125	PERKINS COIE	Legal Services	329,702
126	POTEET CONSTRUCTION	Traffic Safety Services	126,170
127	POWER ENGINEERS	Engineering Services	766,351
129	POWERPLAN INC	Software Implementation Support Services	494,570

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
130	PRO PIPE CORPORATION	Construction	745,185
131	RESPEC	Right of Way Consulting Services	184,031
132	RISING RIVER MONTANA LLC	Construction	78,800
133	RML INCORPORATED	Boring Services	304,684
134	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	30,110,659
135	ROD TABBERT CONSTRUCTION INC	Construction	664,178
136	ROUNDS BROTHERS TRENCHING	Boring Services	379,926
137	S & C ELECTRIC COMPANY	Construction	98,713
138	SCENIC CITY ENTERPRISES INC	Vac Services - Pole Holes	121,548
139	SHUMAKER TRUCKING & EXCAVATING	Excavation Contractor	91,152
140	SIME CONSTRUCTION INC	Construction	282,482
141	SKADDEN, ARPS, SLATE, MEAGHER	Legal Services	1,956,461
142	SLETTEN CONSTRUCTION COMPANY	Construction	141,143
143	SPHERION STAFFING	Temporary Employment Services	464,604
144	STANDARD & POOR'S FINANCIAL SERVICES	Debt Rating Services	378,075
145	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	443,309
146	STEEL ETC HOLDING COMPANY	Rail Installation/Inspection	130,000
147	STINSON LEONARD STREET LLP	Legal Services	208,158
148	STR AND ASSOCIATES PC	Legal Services	239,214
149	SULLWAY CONSTRUCTION INC	Construction	153,671
150	TERRACON CONSULTANTS INC	Engineering Services	176,697
151	THE ELECTRIC COMPANY OF SOUTH DAKOTA	Construction	373,701
152	THE ENERGY AUTHORITY INC	Scheduling and Dispatch	548,687
153	THE ESSEX PARTNERSHIP	Engineering Services	80,555
154	THE L E MYERS CO	Storm Damage Restoration	198,963
155	THE NORTHBRIDGE GROUP INC	FERC Ancillary Filing Services	159,391
156	TITAN ELECTRIC INC	Construction	902,987
157	TODD O BRUESKE CONSTRUCTION	Construction	335,625
158	TOWER SYSTEMS INC	Construction	99,897
159	TOWERS WATSON DATA SERVICES	Compensation Consultants	144,382
160	TP CONSTRUCTION INCORPORATED	Construction	101,329
161	TRADEMARK ELECTRIC INC	Construction	551,506
162	TRI-COUNTY MECHANICAL & ELECTRICAL	Construction	187,283
163	TURBO JET SERVICES	Inspection Services	115,500
164	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	140,834
165	VARSITY CONTRACTORS INC	Janitorial Services	299,652
166	VERTEX	Billing Services and System Implementation	3,109,242
167	VESTA PARTNERS LLC	Hydro Engineering Services	1,423,648
168	WALSH CONSTRUCTION, INC	Construction	110,548
169	WASHINGTON FORESTRY CONSULTANTS	Forestry Consultants	594,764
170	WASLEY EXCAVATING	Construction	88,264
171	WATER & ENVIRONMENTAL TECHNOLOGY	Environmental Engineering Services	176,355
172	WATSON TRUCKING	Water Hauling Services	166,950
173	WHALEN TIRE INC	Tire Inspection Services	100,836
174	WILLIAMS PLUMBING & HEATING INC	Boiler Replacement	84,102
175	WILLIAMSON FENCING INC	Construction	126,960
176	WINSTON & STRAWN LLP	Legal Services	121,502
177	WORKLOGIX MANAGEMENT INC	SAP Consulting	83,992
178	WRIGHT & TALISMAN PC	Legal Services	249,710
179	WRIGHT AND SUDLOW INC	Construction	133,699
180			
181			
182			
183	Total of Payments Set Forth Above		\$ 151,057,430
	1/ This schedule includes payments for professional services over \$75,000.		

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
1	<p>There are three employee political action committees (PAC)s:</p> <p>a. Employees of NorthWestern Corporation (NorthWestern Energy) PAC;</p> <p>b. NorthWestern Energy Employees PAC; and</p> <p>c. NorthWestern Public Service Employees PAC.</p> <p>All of the money contributed by members is dedicated to support political candidates. No company funds may be spent in support of a political candidate. Nominal administrative costs for such things as duplicating, postage, and meeting expenses are paid by the company as provided by law. These costs are charged to shareholder expense.</p>			
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36	<b>TOTAL Contributions</b>	\$ -	\$ -	

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	\$ 510,163,556	\$ 545,833,926	-6.54%
8	Service cost	9,792,283	12,287,637	-20.31%
9	Interest cost	23,633,207	20,553,581	14.98%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	97,569,854	(49,399,148)	297.51%
13	Acquisition	-	-	-
14	Benefits paid	(19,791,487)	(19,112,440)	-3.55%
15	Benefit obligation at end of year	\$ 621,367,413	\$ 510,163,556	21.80%
16	Change in Plan Assets			
17	Fair value of plan assets at beginning of year	\$ 459,232,101	\$ 419,255,762	9.54%
18	Actual return on plan assets	47,571,410	48,588,779	-2.09%
19	Acquisition	-	-	-
20	Employer contribution	9,000,000	10,500,000	-14.29%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(19,791,487)	(19,112,440)	-3.55%
23	Fair value of plan assets at end of year	\$ 496,012,024	\$ 459,232,101	8.01%
24	Funded Status	\$ (125,355,389)	\$ (50,931,455)	-146.13%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	\$ (125,355,389)	\$ (50,931,455)	-146.13%
30	Weighted-average Assumptions as of Year End			
31	Discount rate	3.90%	4.75%	-17.89%
32	Expected return on plan assets	5.80%	7.00%	-17.14%
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	\$ 9,792,283	\$ 12,287,637	-20.31%
36	Interest cost	23,633,207	20,553,581	14.98%
37	Expected return on plan assets	(26,316,885)	(28,886,294)	8.89%
38	Amortization of prior service cost	246,361	246,361	
39	Recognized net actuarial gain	2,117,774	11,138,542	-80.99%
40	Net periodic benefit cost (SEC Basis)	\$ 9,472,740	\$ 15,339,827	-146.13%
41	Montana Intrastate Costs: (MPSC Regulatory Basis)			
42	Pension Costs	\$ 9,000,000	\$ 10,500,000	-14.29%
43	Pension Costs Capitalized	1,822,578	2,161,868	-15.69%
44	Accumulated Pension Asset (Liability) at Year End	\$ (125,355,389)	\$ (50,931,455)	-146.13%
45	Number of Company Employees:			
46	Covered by the Plan	3,041	3,061	-0.65%
47	Not Covered by the Plan 2/	441	342	28.95%
48	Active	860	899	-4.34%
49	Retired	1,432	1,394	2.73%
50	Deferred Vested Terminated	749	768	-2.47%
	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/			
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	<b>Change in Benefit Obligation</b>			
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	<b>Change in Plan Assets</b>			
17	Fair value of plan assets at beginning of year	\$ 312,279,277	\$ 253,146,989	-18.94%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	\$ 8,715,756	\$ 7,790,683	11.87%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	\$ 329,680,178	\$ 312,279,277	5.57%
24	<b>Funded Status</b>		Not Applicable	
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	\$ -	\$ -	
28				
29	<b>Weighted-average Assumptions as of Year End</b>		Not Applicable	
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	<b>Components of Net Periodic Benefit Costs</b>		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	<b>Montana Intrastate Costs: (MPSC Regulatory Basis)</b>			
43	401(k) Plan Defined Contribution Costs	\$ 6,258,247	\$ 5,480,587	14.19%
44	401(k) Plan Defined Contribution Costs Capitalized	1,267,349	1,128,410	12.31%
45	Accumulated Pension Asset (Liability) at Year End		Not Applicable	
46	<b>Number of Company Employees:</b>	3/	3/	
47	Covered by the Plan - Eligible	1,587	1,470	7.96%
48	Not Covered by the Plan			
49	Active - Participating	1,537	1,434	7.18%
50	Retired			
51	Vested Former Employees, Retirees and Active-	259	477	-45.70%
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	<b>Regulatory Treatment:</b>			
2	Commission authorized - most recent			
3	Docket number: D2012.9.94			
4	Order number: 7249e			
5	Amount recovered through rates	(\$101,920)	\$177,804	-157.32%
6	<b>Weighted-average Assumptions as of Year End</b>	1/	2/	
7	Discount rate	3.20%	3.75%	-14.67%
8	Expected return on plan assets	5.80%	7.00%	-17.14%
9	Medical Cost Inflation Rate 3/	8.0%, 4.5%:14	8.25%, 4.5%:15	
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	<b>List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:</b>			
13	Union Employees - VEBA - Yes, tax advantaged			
14	Non-Union Employees - 401(h) - Yes, tax advantaged			
15	<b>Describe any Changes to the Benefit Plan:</b>			
16				
	1/ Obtained from NorthWestern Energy-Montana's 2014 FASB 106 Valuation. Assumptions and data are as of December 31, 2014. 2/ Obtained from NorthWestern Energy-Montana's 2013 FASB 106 Valuation. Assumptions and data are as of December 31, 2013. 3/ First Year, Ultimate, Years to Reach Ultimate.			

Sch. 15a	Post Employment Benefits (OPEBS) (continued)			
	Item	Current Year	Last Year	% Change
1	<b>Number of Company Employees:</b>			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active			
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	<b>Montana 4/</b>			
8	<b>Change in Benefit Obligation</b>			
9	Benefit obligation at beginning of year	\$20,677,119	\$23,181,823	-10.80%
10	Service cost	374,530	434,332	-13.77%
11	Interest Cost	743,834	616,759	20.60%
12	Plan participants' contributions	576,792	775,242	-25.60%
13	Amendments	-	-	-
14	Actuarial loss/(gain)	896,216	(2,304,870)	138.88%
15	Acquisition	-	-	-
16	Benefits paid	(2,301,355)	(2,026,167)	-13.58%
17	Benefit obligation at end of year	\$20,967,136	\$20,677,119	1.40%
18	<b>Change in Plan Assets</b>			
19	Fair value of plan assets at beginning of year	\$18,183,195	\$15,893,406	14.41%
20	Actual return on plan assets	1,390,832	2,661,840	-47.75%
21	Acquisition	-	-	-
22	Employer contribution	190,853	878,874	-78.28%
23	Plan participants' contributions	576,792	775,242	-25.60%
24	Benefits paid	(2,301,355)	(2,026,167)	-13.58%
25	Fair value of plan assets at end of year	\$18,040,317	\$18,183,195	-0.79%
26	<b>Funded Status</b>	(\$2,926,819)	(\$2,493,924)	-17.36%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	(\$2,926,819)	(\$2,493,924)	-17.36%
31	<b>Components of Net Periodic Benefit Costs</b>			
32	Service cost	\$374,530	\$434,332	-13.77%
33	Interest cost	743,834	616,759	20.60%
34	Expected return on plan assets	(980,569)	(1,019,000)	3.77%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,148,915)	(2,148,915)	-
37	Recognized net actuarial loss/(gain)	347,876	733,305	-52.56%
38	Net periodic benefit cost	(\$1,663,244)	(\$1,383,519)	-20.22%
39	<b>Accumulated Post Retirement Benefit Obligation</b>			
40	Amount Funded through VEBA	\$ -	\$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	190,853	878,875	-78.28%
43	TOTAL	\$190,853	\$878,875	-78.28%
44	Amount that was tax deductible - VEBA	\$ -	\$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(101,920)	177,804	-157.32%
47	TOTAL	(\$101,920)	\$177,804	-157.32%
48	<b>Montana Intrastate Costs:</b>			
49	Pension Costs	(\$101,920)	\$177,804	-157.32%
50	Pension Costs Capitalized	(20,640)	36,608	-156.38%
51	Accumulated Pension Asset (Liability) at Year End	(2,926,819)	(2,493,924)	-17.36%
52	<b>Number of Montana Employees:</b>			
53	Covered by the Plan	1,913	1,971	-2.94%
54	Not Covered by the Plan	92	148	-37.84%
55	Active	887	926	-4.21%
56	Retired	932	950	-1.89%
57	Spouses/Dependants covered by the Plan	94	95	-1.05%
	4/ There is approximately an additional \$9,037,879 and \$9,406,969 in other company OPEBS liabilities outstanding at December 31, 2014 and 2013, 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	Michael R. Cashell Vice President, Transmission	204,827	91,019 A	32,663 B 109,722 C 5,980 D 257,794 E	702,005	379,396	85%
2	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	217,201	95,787 A	21,482 B 117,859 C 244,870 E 37 F	697,236	390,824	78%
3	Bobbi L. Schroepel Vice President, Customer Care, Communications & Human Resources	239,493	106,423 A	48,610 B 128,277 C 36,563 E	559,366	449,228	25%
4	John D. Hines Vice President, Supply	204,827	91,019 A	19,158 B 109,722 C 3,609 D 103,640 E 37 F	532,012	377,938	41%
5	William T. Rhoads General Manager, Generation	177,329	44,688 A	24,073 B 34,727 C 6,946 D 222,800 E 459 F	511,022	265,549	92%
6	Michael L. Nieman Chief Audit and Compliance Officer	204,257	64,342 A	49,022 B 49,982 C 39,678 E 37 F	407,318	335,650	21%
7	Daniel L. Rausch Treasurer	193,629	61,151 A	46,716 B 47,031 C 6,785 D 28,623 E	383,935	327,888	17%
8	Jeanne M. Vold Business Technology Officer	176,341	55,691 A	25,660 B 42,853 C 20,177 E	320,722	304,227	5%
9	Wayne M. Hitt Director Tax	159,191	39,798 A	38,076 B 31,852 C 10,506 E	279,423	N/A	
10	Timothy P. Olson Corporate Counsel & Corp Secretary	160,112	40,483 A	41,088 B 31,047 C	272,730	N/A	

**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	1/ Bonuses include the following:						
2							
3	A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2014						
4	Annual Incentive Compensation Plan. Amounts were earned in 2014 and paid in the first quarter of 2015.						
5	Based on company performance against plan, the incentive plan was funded at 125% of target.						
6	Individual awards varied from the funded level based on individual performance.						
7							
8	2/ All Other Compensation for named employees consists of the following:						
9							
10	B> Employer contributions to benefits - medical, dental, vision, employee assistance program,						
11	group term life, Health Savings Account, wellness incentive, 401(k) match, and non-elective						
12	401(k) contribution.						
13							
14	C> Values reflect the grant date fair value for performance stock awards.						
15							
16	D> Vacation sold back during the year.						
17							
18	E> Change in pension value over previous year. The present value of accumulated benefits was calculated						
19	assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed						
20	payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements						
21	in our Annual Report on Form 10-K for the year ended December 31, 2014.						
22							
23	F> Noncash taxable award and tax gross-up on award.						
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							

**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	556,924	561,389 A	22,114 B 1,098,234 C 104,139 D 41 E	2,342,841	1,724,898	36%
2	Brian B. Bird Vice President & Chief Financial Officer	365,351	230,175 A	49,005 B 422,840 C 32,002 D	1,099,373	871,971	26%
3	Heather H. Grahame Vice President & General Counsel	332,462	188,509 A	46,592 B 278,547 C 37 E	846,147	692,658	22%
4	Curtis T. Pohl Vice President, Distribution Operations	261,754	131,927 A	52,842 B 206,470 C 64,786 D 9,237 F	727,016	558,633	30%
5	Kendall Kliever Vice President & Controller	241,478	106,494 A	46,366 B 131,043 C 36,373 D	561,754	458,055	23%

**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	1/ Bonuses include the following:						
2							
3	A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2014						
4	Annual Incentive Compensation Plan. Amounts were earned in 2014 and paid in the first quarter of 2015.						
5	Based on company performance against plan, the incentive plan was funded at 125% of target.						
6							
7	2/ All Other Compensation for named employees consists of the following:						
8							
9	B> Employer contributions to benefits - medical, dental, vision, employee assistance program,						
10	group term life, Health Savings Account, wellness incentive, 401(k) match, and non-elective 401(k) contribution.						
11							
12	C> Values reflect the grant date fair value for performance stock awards.						
13							
14	D> Change in pension value over previous year. The present value of accumulated benefits was calculated						
15	assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed						
16	payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements						
17	in our Annual Report on Form 10-K for the year ended December 31, 2014.						
18							
19	E> Noncash taxable award and tax gross-up on award.						
20							
21	F> Vacation sold back during the year.						
22							
23							
24							
25							

Sch. 18	BALANCE SHEET 1/				
	Account Title	This Year	Last Year	Variance	% Change
1	<b>Assets and Other Debits</b>				
2	Utility Plant				
3	101 Plant in Service	\$4,612,121,385	\$3,974,701,127	\$637,420,258	16.04%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	-	0.00%
5	105 Plant Held for Future Use	3,558,413	3,560,555	(2,142)	-0.06%
6	107 Construction Work in Progress	213,126,467	97,044,707	\$116,081,760	119.62%
7	108 Accumulated Depreciation Reserve	(1,690,819,946)	(1,616,152,234)	(\$74,667,712)	4.62%
8	108.1 Accumulated Depreciation - Capital Leases	(17,089,022)	(15,078,542)	(\$2,010,480)	13.33%
9	111 Accumulated Amortization & Depletion Reserves	(37,112,782)	(27,467,302)	(\$9,645,480)	35.12%
10	114 Electric Plant Acquisition Adjustments	350,132,657	-	350,132,657	-
11	115 Accumulated Amortization-Electric Plant Acq. Adj.	(937,002)	-	(937,002)	-
12	116 Utility Plant Adjustments	355,128,500	355,128,500	-	0.00%
13	117 Gas Stored Underground-Noncurrent	32,135,879	32,120,387	15,492	0.05%
14	<b>Total Utility Plant</b>	<b>3,860,454,086</b>	<b>2,844,066,735</b>	<b>1,016,387,351</b>	<b>35.74%</b>
15	<b>Other Property and Investments</b>				
16	121 Nonutility Property	6,749,606	6,749,606	-	0.00%
17	122 Accumulated Depr. & Amort.-Nonutility Property	(1,154,851)	(819,346)	(335,505)	-40.95%
18	123.1 Investments in Assoc Companies and Subsidiaries	(140,450,323)	(141,594,938)	1,144,615	-0.81%
19	124 Other Investments	39,899,904	16,784,220	23,115,684	137.72%
20	128 Miscellaneous Special Funds	16,787,692	-	16,787,692	-
21	LT Portion of Derivative Assets - Hedges	-	-	-	-
22	<b>Total Other Property &amp; Investments</b>	<b>(78,167,972)</b>	<b>(118,880,458)</b>	<b>40,712,486</b>	<b>-34.25%</b>
23	<b>Current and Accrued Assets</b>				
24	131 Cash	12,841,079	10,387,435	2,453,644	23.62%
25	134 Other Special Deposits	10,528,068	4,169,290	6,358,778	152.51%
26	135 Working Funds	42,575	40,125	2,450	6.11%
27	136 Temporary Cash Investments	-	-	-	-
28	141 Notes Receivable	-	-	-	-
29	142 Customer Accounts Receivable	83,662,524	88,584,019	(4,921,495)	-5.56%
30	143 Other Accounts Receivable	16,550,278	16,564,952	(14,674)	-0.09%
31	144 Accumulated Provision for Uncollectible Accounts	(4,301,616)	(4,451,666)	150,050	-3.37%
32	145 Notes Receivable-Associated Companies	-	-	-	-
33	146 Accounts Receivable-Associated Companies	344,565	148,135	196,430	132.60%
34	151 Fuel Stock	7,630,351	8,460,264	(829,913)	-9.81%
35	154 Plant Materials and Operating Supplies	29,082,484	26,791,411	2,291,411	8.55%
36	164 Gas Stored - Current	16,360,518	18,351,754	(1,991,236)	-10.85%
37	165 Prepayments	13,818,312	13,775,768	42,544	0.31%
38	171 Interest and Dividends Receivable	-	-	-	-
40	172 Rents Receivable	204,569	80,272	124,297	154.84%
41	173 Accrued Utility Revenues	70,315,316	74,345,656	(4,030,340)	-5.42%
42	174 Miscellaneous Current & Accrued Assets	30,019,535	877	30,018,658	>300.00%
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	<b>Total Current &amp; Accrued Assets</b>	<b>287,098,558</b>	<b>257,247,954</b>	<b>29,850,604</b>	<b>11.60%</b>
48	<b>Deferred Debits</b>				
49	181 Unamortized Debt Expense	13,041,834	13,614,516	(572,682)	-4.21%
50	182 Regulatory Assets	463,907,330	324,402,612	139,504,718	43.00%
51	183 Preliminary Survey and Investigation Charges	1,185,617	1,185,617	-	0.00%
52	184 Clearing Accounts	900	30,449	(29,549)	-97.04%
53	185 Temporary Facilities	-	-	-	-
54	186 Miscellaneous Deferred Debits	530,880	876,649	(345,769)	-39.44%
55	189 Unamortized Loss on Reacquired Debt	12,151,208	13,918,710	(1,767,502)	-12.70%
56	190 Accumulated Deferred Income Taxes	186,187,313	125,015,983	61,171,330	48.93%
57	191 Unrecovered Purchased Gas Costs	25,520,064	16,260,432	9,259,632	56.95%
58	<b>Total Deferred Debits</b>	<b>702,525,146</b>	<b>495,304,968</b>	<b>207,220,178</b>	<b>41.84%</b>
59	<b>TOTAL ASSETS and OTHER DEBITS</b>	<b>\$ 4,771,909,818</b>	<b>\$ 3,477,739,199</b>	<b>\$ 1,294,170,619</b>	<b>37.21%</b>

Sch. 18	cont.	BALANCE SHEET 1/			
	Account Title	This Year	Last Year	Variance	% Change
1	<b>Liabilities and Other Credits</b>				
2	<b>Proprietary Capital</b>				
3	201 Common Stock Issued	\$ 505,226	\$ 423,405	\$ 81,821	19.32%
4	204 Preferred Stock Issued	-	-	-	-
5	207 Premium on Capital Stock	-	-	-	-
6	211 Miscellaneous Paid-In Capital	1,313,844,035	910,184,562	403,659,473	44.35%
7	213 Discount on Capital Stock	-	-	-	-
8	214 Capital Stock Expense	-	-	-	-
9	215 Appropriated Retained Earnings	-	-	-	-
10	216 Unappropriated Retained Earnings	264,757,908	209,090,660	55,667,248	26.62%
12	217 Reacquired Capital Stock	(92,558,283)	(91,744,257)	(814,026)	0.89%
13	219 Accumulated Other Comprehensive Income	(8,765,944)	2,716,002	(11,481,946)	>-300.00%
14	<b>Total Proprietary Capital</b>	<b>1,477,782,942</b>	<b>1,030,670,372</b>	<b>447,112,570</b>	<b>43.38%</b>
15	<b>Long Term Debt</b>				
16	221 Bonds	1,635,205,000	1,155,205,000	480,000,000	41.55%
17	223 Advances in Associated Companies	-	-	-	-
18	224 Other Long Term Debt	26,976,900	-	26,976,900	-
19	226 (Less) Unamortized Discount on Long Term Debt-Debit	83,438	107,538	(24,100)	-22.41%
20	<b>Total Long Term Debt</b>	<b>1,662,098,462</b>	<b>1,155,097,462</b>	<b>507,001,000</b>	<b>43.89%</b>
21	<b>Other Noncurrent Liabilities</b>				
22	227 Obligations Under Capital Leases-Noncurrent	28,162,445	29,894,898	(1,732,453)	-5.80%
23	228.1 Accumulated Provision for Property Insurance	-	-	-	-
24	228.2 Accumulated Provision for Injuries and Damages	9,061,051	8,748,808	312,243	3.57%
25	228.3 Accumulated Provision for Pensions and Benefits	20,244,171	19,808,834	435,337	2.20%
26	228.4 Accumulated Miscellaneous Operating Provisions	164,953,264	164,641,920	311,344	0.19%
27	229 Accumulated Provision for Rate Refunds	34,280,250	27,235,028	7,045,222	25.87%
28	230 Asset Retirement Obligations	21,435,223	18,803,779	2,631,444	13.99%
29	<b>Total Other Noncurrent Liabilities</b>	<b>278,136,404</b>	<b>268,133,267</b>	<b>9,003,137</b>	<b>3.35%</b>
30	<b>Current and Accrued Liabilities</b>				
31	231 Notes Payable	267,840,079	140,949,554	126,890,525	90.03%
32	232 Accounts Payable	90,659,542	97,936,435	(7,276,893)	-7.43%
33	233 Notes Payable to Associated Companies	-	-	-	-
34	234 Accounts Payable to Associated Companies	1,466,006	1,420,295	45,711	3.22%
35	235 Customer Deposits	6,621,535	10,847,568	(4,226,033)	-38.96%
36	236 Taxes Accrued	39,264,570	41,116,000	(1,851,430)	-4.50%
37	237 Interest Accrued	19,734,213	18,038,039	1,696,174	9.40%
39	238 Dividends Declared	-	-	-	-
40	241 Tax Collections Payable	1,892,527	1,467,454	425,073	28.97%
41	242 Miscellaneous Current and Accrued Liabilities	63,800,309	57,359,786	6,440,523	11.23%
42	243 Obligations Under Capital Leases-Current	1,729,507	1,662,235	67,272	4.05%
43	244 Derivative Instrument Liabilities	-	-	-	-
44	245 Derivative Instrument Liabilities - Hedges	18,310,043	-	18,310,043	-
45	<b>Total Current and Accrued Liabilities</b>	<b>511,318,331</b>	<b>370,797,366</b>	<b>140,520,965</b>	<b>37.90%</b>
46	<b>Deferred Credits</b>				
47	252 Customer Advances for Construction	30,000,627	27,370,414	2,630,213	9.61%
48	253 Other Deferred Credits	171,200,388	94,739,483	76,460,905	80.71%
49	254 Regulatory Liabilities	26,470,224	22,852,872	3,617,352	15.83%
50	255 Accumulated Deferred Investment Tax Credits	588,781	861,860	(273,079)	-31.68%
51	257 Unamortized Gain on Reacquired Debt	-	-	-	-
52	281-283 Accumulated Deferred Income Taxes	614,313,659	506,216,103	108,097,556	21.35%
53	<b>Total Deferred Credits</b>	<b>842,573,679</b>	<b>652,040,732</b>	<b>190,532,947</b>	<b>29.22%</b>
54	<b>TOTAL LIABILITIES and OTHER CREDITS</b>	<b>\$ 4,771,909,818</b>	<b>\$ 3,477,739,199</b>	<b>\$ 1,294,170,619</b>	<b>37.21%</b>

1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.

## NOTES TO FINANCIAL STATEMENTS

### (1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 692,600 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, 2014, have been evaluated as to their potential impact to the Financial Statements through the date of issuance. Our November 2014 acquisition of hydro generating assets is included in the results of operations for the year ended December 31, 2014, and impacts the comparability of the current year financial statements to prior years. For a further discussion of this acquisition, see Note 3 - Hydro Transaction.

### (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 \$351.7 million and \$336.6 million as of December 31, 2014 and December 31, 2013, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes;
- Goodwill is reflected in the Balance Sheets as a utility plant adjustment of \$355.1 million as of December 31, 2014 and December 31, 2013, 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, 2014 and December 31, 2013, 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 \$4.3 million and \$4.5 million at December 31, 2014 and December 31, 2013, respectively. Unbilled revenues were \$70.3 million and \$74.3 million at December 31, 2014 and December 31, 2013, respectively.

### Inventories

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

	December 31,	
	2014	2013
Fuel stock	\$ 7,630	\$ 8,460
Plant materials and operating supplies	29,082	26,791
Gas stored underground (including the non-current portion reflected in utility plant)	48,496	50,472
	<u>\$ 85,208</u>	<u>\$ 85,723</u>

### Regulation of Utility Operations

Our regulated operations are subject to the provisions of 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 8.0% and 8.1%, for Montana and South Dakota for 2014 and 2013, respectively. AFUDC capitalized totaled \$10.8 million for the year ended December 31, 2014 and \$8.2 million for the year ended December 31, 2013 for Montana and South Dakota combined.

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 50 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 2.9% and 3.2% for 2014 and 2013, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission our jointly owned plants at the end of the useful life. 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.

### **Business Combination**

Our November 2014 acquisition of hydro generating assets was accounted for using business combination accounting. Under this method, the purchase price paid by the acquirer is allocated to the assets acquired and liabilities assumed as of the acquisition date based on their fair value. For additional information see Note 3 - Hydro Transaction.

### **Accounting Standards Issued**

In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance on the recognition of revenue from contracts with customers, which will supersede nearly all existing revenue recognition guidance under GAAP.

Under the new standard, entities will recognize revenue to depict the transfer of goods and services to customers in amounts that reflect the payment to which the entity expects to be entitled in exchange for those goods or services. The guidance also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows from an entity's contracts with customers. The new guidance will be effective for us in our first quarter of 2017. Early adoption is not permitted. We are currently evaluating the impact of adoption of this new guidance on our Financial Statements and disclosures.

In January 2015, the FASB issued guidance which eliminates from GAAP the concept of an extraordinary item. As a result, an entity will no longer (1) segregate an extraordinary item from the results of ordinary operations; (2) separately present an extraordinary item on its income statement, net of tax, after income from continuing operations; and (3) disclose income taxes and earnings-per-share data applicable to an extraordinary item. The new guidance will be effective for us in our first quarter of 2016 and early adoption is permitted. We do not expect the adoption of this standard to have a material effect on our reporting and disclosure.

### **Accounting Standards Adopted**

There have been no new accounting pronouncements or changes in accounting pronouncements adopted during the period that are of significance, or potential significance, to us.

### **(3) Hydro Transaction**

In November 2014, we completed the purchase of hydroelectric generating facilities and associated assets located in Montana for an adjusted purchase price of approximately \$904 million (Hydro Transaction). The addition of hydroelectric generation is intended to provide long-term supply diversity to our portfolio and reduce risks associated with variable fuel prices. We expect the Hydro Transaction to allow us to reduce our reliance on third party power purchase agreements and spot market purchases, more closely matching our electric generation resources with forecasted customer demand. With reduced amounts of purchased power, we believe we will be less exposed to market volatility and will be better positioned to control the cost of supplying electricity to our customers.

The facilities acquired include eleven hydro-electric plants and one storage reservoir (each a "Facility" and together the "Facilities") located in central and western Montana along the Missouri, Flathead, Clark Fork and Madison Rivers and Rosebud Creek. The net aggregate generating capacity of the Facilities is 633 MWs, which includes the Kerr Project, a 194 MW hydroelectric generating facility that we expect to transfer to the Confederated Salish and Kootenai Tribes of the Flathead Reservation (CSKT) in September 2015. See further discussion below. Eight of the Facilities, along with the storage reservoir, are collectively licensed as the Missouri-Madison Project, by the FERC. Each of the remaining three Facilities is licensed by FERC as a separate project.

With the addition of these generating assets and assuming ownership of the Kerr Project is transferred as discussed below, we own generation facilities that provide approximately 60% of our average electric load serving requirements in Montana. The following chart provides an overview of the facilities by name, net capacity in MWs, commercial operation date (COD), river source, FERC license expiration date and average capacity factor. We are the sole direct owner of each facility.

Plant	COD	River Source	FERC License Expiration	Net Capacity (MW) (1)
Black Eagle	1927	Missouri	2040	21
Cochrane	1958	Missouri	2040	69
Hauser	1911	Missouri	2040	19
Holter	1918	Missouri	2040	48
Madison	1906	Madison	2040	8
Morony	1930	Missouri	2040	48
Mystic	1925	West Rosebud Creek	2050	12
Rainbow	1910/2013	Missouri	2040	60
Ryan	1915	Missouri	2040	60
Thompson Falls	1915	Clark Fork	2025	94
<b>Subtotal</b>				<b>439</b>
Kerr	1938	Flathead	2035	194
<b>Total</b>				<b>633</b>

(1) Hebgen facility (0 MW net capacity) excluded from figures. These are run-of-river dams except for Kerr and Mystic, which are storage generation.

The purchase price was allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition as follows:

Purchase Price Allocation	(in millions)
<b>Assets Acquired</b>	
Inventory	\$ 0.2
Utility Plant	899.6
Prepayments	4.5
<b>Total Assets Acquired</b>	<b>\$ 904.3</b>
<b>Liabilities Assumed</b>	
Miscellaneous Current and Accrued Liabilities	\$ 0.4
Other Deferred Credits	0.4
<b>Total Liabilities Assumed</b>	<b>\$ 0.8</b>
<b>Total Purchase Price</b>	<b>\$ 903.5</b>

We expect to finalize the purchase price allocation, including analysis of environmental matters and potential removal obligations, during the first half of 2015. Pro forma adjustments to our revenues and earnings prior to the date of acquisition would not be meaningful. Prior to the acquisition, the Facilities were nonregulated with output sold to third parties. These Facilities are now part of our regulated fleet used to serve our customers.

**Regulatory Approvals** - On September 26, 2014, the Montana Public Service Commission (MPSC) issued a final order (MPSC Order) approving the application, subject to certain conditions, including the following:

- Inclusion of \$870 million of the \$904 million purchase price for the hydro assets in our Montana jurisdictional rate base with a 50-year life;
- Return on equity of 9.8%, a cost of debt of 4.25%, and a capital structure of 52% debt and 48% equity, resulting in an associated first year annual retail revenue requirement of approximately \$117 million;
- A final compliance filing in December 2015 to reflect post-closing adjustments, the conveyance of the Kerr Project as discussed below and the actual property tax expense for the Hydroelectric facilities; and
- Tracking of revenue credits on a portfolio basis through our electricity supply cost tracker.

**Financing** - We financed the Hydro Transaction with a combination of \$450 million of long-term debt, \$400 million of equity and cash flows from operations. See Note 13 - Long-Term Debt and Note 20 - Common Stock for further detail on these transactions.

**Kerr Project** - The Hydro Transaction includes the Kerr Project, a 194 MW hydro-electric generating facility that we expect will be transferred to the Confederated Salish and Kootenai Tribes of the Flathead Reservation (CSKT) in September 2015, in accordance with its FERC license, which gives the CSKT the right to acquire the project between September 2015 and September 2025. The CSKT have formally provided notice of their intent to acquire the Kerr Project and designated September 5, 2015, as the date for conveyance to occur. PPL Montana and the CSKT previously conducted an arbitration over the conveyance price of the Kerr Project. In March 2014, an arbitration panel set an estimated conveyance price of approximately \$18.3 million. Under our agreement with PPL Montana, the purchase price for the Hydro Transaction includes a \$30 million reference price for the Kerr Project. If the CSKT complete the acquisition and pay \$18.3 million for the Kerr Project, PPL Montana will pay the difference of \$11.7 million to us. We expect to sell any excess generation from the Kerr Project in the market and provide revenue credits to our Montana retail customers until the CSKT exercises their right to acquire the Kerr Project. The MPSC Order provides that customers will have no financial risk related to our temporary ownership of the Kerr Project, with a compliance filing required upon completion of the transfer to CSKT.

During the twelve months ended December 31, 2014, we incurred approximately \$9.5 million of legal and professional fees associated with the Hydro Transaction, which are included in operating expense, and approximately \$5.8 million of expenses related to the bridge credit facility included in interest on long-term debt.

#### **(4) Regulatory Matters**

##### **South Dakota Electric Rate Filing**

In December 2014, we filed a request with the SDPUC for an annual increase to electric rates totaling approximately \$26.5 million. Our request was based on a return on equity of 10%, a capital structure consisting of 46% debt and 54% equity and rate base of \$447.4 million. We anticipate implementing interim rates during July 2015. The SDPUC has not yet issued a procedural schedule.

##### **Dave Gates Generating Station at Mill Creek (DGGS)**

In April 2014, the FERC issued an order affirming a FERC Administrative Law Judge's (ALJ) initial decision in September 2012, regarding cost allocation at DGGS between retail and wholesale customers. This decision concluded we should allocate only a fraction of the costs we believe, based on facts and the law, should be allocated to FERC jurisdictional customers. We have been recognizing revenue consistent with the ALJ's initial decision. As of March 31, 2015, we have cumulative deferred revenue of approximately \$27.3 million, which is subject to refund and recorded within accumulated provision for rate refunds in the Balance Sheets.

In May 2014, we filed a request for rehearing, which remains pending. In our request for rehearing, we have argued that no refunds are due even if the cost allocation method is modified prospectively. There is no deadline by which FERC must act on our rehearing petition, but it could occur during 2015. Customer refunds, if any, will not be due until 30 days after a FERC order on rehearing. If unsuccessful on rehearing, we may appeal to a United States Circuit Court of Appeals. The time line for any such appeal could, depending on when the FERC issues a rehearing order, extend into 2016 or beyond.

The FERC order was assessed as a triggering event as to whether an impairment charge should be recorded with respect to DGGS. We continue to evaluate options to use DGGS in combination with other generation resources, including our newly acquired hydro facilities, to ensure cost recovery. Any alternative use of DGGS would be subject to regulatory approval and we cannot provide assurance of such approval. We do not believe an impairment loss is probable at this time; however, we will continue to evaluate recovery of this asset in the future as facts and circumstances change.

## **Montana Electric Tracker Filings**

Each year we submit an electric tracker filing 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 supply procurement activities were prudent.

Our electric supply tracker filings for the 2013/2014 and 2012/2013 tracker periods are part of a consolidated docket, which is still subject to final approval by the MPSC. Our 2014 electric tracker filing included market purchases made between July 2013 and January 2014 for replacement power during an outage at Colstrip Unit 4. Inclusion of these costs in the tracker filing is consistent with the treatment of replacement power during previous outages. During a June 2014 MPSC work session, approximately \$11 million of these incremental market purchases related to the Colstrip Unit 4 outage were identified by the MPSC for additional prudence review. The Montana Environmental Information Center and Sierra Club have intervened in the consolidated docket to challenge our recovery of costs associated with Colstrip Unit 4, particularly the costs incurred as a result of the outage, as imprudent. Discovery is currently in process and a hearing is scheduled for October 2015.

## **Montana Lost Revenue Adjustment Mechanism**

Demand-side management (DSM) lowers our sales to customers. In 2005, the MPSC created a Lost Revenue Adjustment Mechanism (LRAM) by which we collect revenue that we would have collected without any DSM. In an order issued in October 2013, which was related to our 2011 / 2012 electric supply tracker, the MPSC required us to lower our LRAM revenue recovery and imposed a new burden of proof on us for future LRAM recovery. We appealed the October 2013 order to Montana District Court. The appeal is pending. The District Court approved a partial settlement of our appeal, in which the MPSC agreed to remove from the October 2013 order the sentence that imposed the new burden and to initiate a separate docket to review lost revenue policy issues. The MPSC initiated the new proceeding regarding LRAM in June 2014 and a hearing is scheduled for June 2015. Discovery and additional testimony is currently in process.

Based on the MPSC's October 2013 order, we have recognized \$7.1 million of DSM lost revenues for each annual electric supply tracker period. However, since the 2012/2013 and 2013/2014 annual electric tracker filings are 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.

## **Montana Natural Gas Tracker Filings and Natural Gas Production Assets**

Each year we submit a natural gas tracker filing 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 natural gas supply procurement activities were prudent.

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 \$38.5 million of revenue, a portion of which may be subject to refund.

Our annual natural gas supply tracker filings for the 2013/2014 and 2012/2013 tracker periods are part of a consolidated docket, which is still subject to final approval by the MPSC. During March 2015, the Montana Consumer Counsel (MCC) filed testimony that included a recommendation to reduce our natural gas production rates. We disagree with the MCC's recommendation and our rebuttal testimony is due by April 24, 2015. If the MPSC ultimately adopts the MCC's recommendation, it could result in refunds of approximately \$3.0 million previously recognized as revenue. A hearing is scheduled for May 2015.

## (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,	
	2014	2013
Colstrip Unit 4 Basis Adjustment	\$ (156,806)	\$ (159,895)
Havre Pipeline Company, LLC	12,912	14,576
NorthWestern Services, LLC	1,883	1,876
Risk Partners Assurance, Ltd.	1,561	1,848
Total Investments in Subsidiary Companies	\$ (140,450)	\$ (141,595)

## (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.

	Note Reference	Remaining Amortization Period	December 31,	
			2014	2013
			(in thousands)	
Pension	18	Undetermined	\$ 139,050	\$ 58,474
Employee related benefits	18	Undetermined	19,080	17,700
Distribution infrastructure projects		3 Years	9,407	12,543
Environmental clean-up	21	Various	13,741	14,924
Income taxes	15	Plant Lives	263,764	201,808
State & local taxes & fees		Various	5,307	6,582
Other		Various	13,558	12,372
Total regulatory assets			\$ 463,907	\$ 324,403
Gas storage sales		25 Years	\$ 10,410	\$ 10,831
Unbilled revenue		1 Year	10,877	9,868
Environmental clean-up		Various	2,533	1,226
State & local taxes & fees		1 Year	511	551
Other		Various	2,139	377
Total regulatory liabilities			\$ 26,470	\$ 22,853

### 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 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, which began in 2013.

### 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)

The MPSC has authorized recovery in the property tax tracker of approximately 60% of the estimated increase as compared with the related amount included in rates during our last 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,	
	2014	2013
Land and improvements	\$ 137,098	\$ 128,886
Building and improvements	345,451	236,668
Storage, distribution, and transmission	2,769,946	2,641,121
Generation	1,483,137	757,698
Construction work in process	213,126	97,045
Other equipment	270,390	253,891
	5,219,148	4,115,516
Less accumulated depreciation	(1,745,959)	(1,658,698)
	\$ 3,473,189	\$ 2,456,818

In 2014, we acquired hydro generating assets which resulted in an increase of approximately \$870 million in utility plant. We recorded the plant assets at original cost, less accumulated depreciation with an acquisition adjustment in accordance with FERC rules. Utility plant under capital lease were \$23.4 million and \$25.6 million as of December 31, 2014 and 2013,



respectively, which included \$23.1 million and \$25.1 million as of December 31, 2014 and 2013, 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)
<b>December 31, 2014</b>				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	\$ 61,628	\$ 59,579	\$ 46,045	\$ 292,806
Accumulated depreciation	46,741	27,742	36,649	72,976
<b>December 31, 2013</b>				
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

## (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 relate to the reclamation and removal costs at our jointly-owned coal-fired generation facilities, 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,	
	2014	2013
Liability at January 1,	\$ 20,886	\$ 9,283
Accretion expense	1,073	745
Liabilities incurred	552	8,829
Liabilities settled	(85)	(27)
Revisions to cash flows	(991)	2,056
Liability at December 31,	\$ 21,435	\$ 20,886

In addition, 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. We also identified AROs associated with our Hydro Transaction; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the financial statements

We collect removal costs in rates for certain transmission and distribution assets that do not have associated AROs. 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.

## (9) Utility Plant Adjustments

We completed our annual utility plant adjustments impairment test as of April 1, 2014 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 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 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, 2014 and 2013. 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.

### **Credit Risk**

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 limit credit risk in our commodity and interest rate derivative activities by assessing the creditworthiness of potential counterparties before entering into transactions and continuing to evaluate their creditworthiness on an ongoing basis.

We are exposed to credit risk through buying and selling electricity and natural gas to serve customers. 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.

### Interest Rate Swaps Designated as Cash Flow Hedges

In September 2014, we entered into two forward starting swaps of \$225 million each at 3.217% and 3.227% to hedge the risk of changes in the interest payments attributable to changes in the benchmark interest rate during the period from the effective date of the swap to the anticipated date of the debt issuance of \$450 million associated with the Hydro Transaction. These forward starting interest rate swaps were designated as cash flow hedges at the time the agreements were executed. In November 2014, the interest rate swap agreements were terminated and the settlement resulted in a \$18.4 million loss recorded as a component of accumulated other comprehensive income (AOCI).

Amounts are reclassified 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 the interest rate swaps terminated in November 2014 and interest rate swaps previously terminated on the Financial Statements (in thousands):

Cash Flow Hedges	Location of Amount Reclassified from AOCI to Income	Amount Reclassified from AOCI into Income during the Year Ended December 31, 2014
Interest rate contracts	Interest on long-term debt	\$ 1,111

A net loss of approximately \$13.8 million is remaining in AOCI as of December 31, 2014, and we expect to reclassify approximately \$0.6 million of net pre-tax gains from AOCI into interest on long-term debt during the next twelve months. These amounts relate to terminated swaps, and we have no 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.

Applicable accounting guidance establishes a 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. 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, 2014	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	\$ 10,528	\$ —	\$ —	\$ —	\$ 10,528
Rabbi trust investments	21,594	—	—	—	21,594
<b>Total</b>	<b>\$ 32,122</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 32,122</b>

December 31, 2013					
Other special deposits	\$ 4,169	\$ —	\$ —	\$ —	\$ 4,169
Rabbi trust investments	16,477	—	—	—	16,477
<b>Total</b>	<b>\$ 20,646</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 20,646</b>

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.

## Financial Instruments

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

	December 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
<b>Liabilities:</b>				
Long-term debt	\$ 1,662,099	\$ 1,817,642	\$ 1,155,097	\$ 1,237,151

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):

Notes Payable	2014		2013	
	Balance	Interest Rate	Balance	Interest Rate
Commercial Paper	\$ 267.8	0.50%	\$ 141.0	0.41%

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

	2014	2013
Maximum short-term debt outstanding	\$ 276.9	\$ 199.9
Average short-term debt outstanding	\$ 132.5	\$ 69.0
Weighted-average interest rate	0.39%	0.40%

In the fourth quarter of 2014, we increased the size of our commercial paper program from \$250 million to \$340 million. Under the program we may issue unsecured commercial paper notes on a private placement basis 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

In the fourth quarter of 2014, we exercised the accordion feature under our \$300 million unsecured revolving credit facility to increase the size to \$350 million. The facility does not amortize and is scheduled to expire on November 5, 2018. 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 21% of the total availability. There were no direct borrowings or letters of credit outstanding as of December 31, 2014. Commitment fees for the unsecured revolving line of credit were \$0.4 million and \$0.5 million for the years ended December 31, 2014 and 2013, respectively.

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 was not drawn upon and cancelled in November 2014.

(13) Long-Term Debt

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

		December 31,	
	Due	2014	2013
<b>Unsecured Debt:</b>			
Unsecured Revolving Line of Credit	2018	\$ —	\$ —
<b>Secured Debt:</b>			
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	50,000
South Dakota—4.22%	2044	30,000	—
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	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	—
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
<b>Other Long Term Debt:</b>			
New Market Tax Credit Financing—1.146%	2046	26,977	—
Discount on Notes and Bonds	—	(83)	(108)
		\$ 1,662,099	\$ 1,155,097

**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 2014, we issued \$30 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 4.22% maturing in 2044. The bonds are secured by our electric and natural gas assets in South Dakota and were issued in a transaction 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.

*Hydro Transaction Issuance* - In November 2014, we issued \$450 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 4.176% maturing in 2044 as a portion of the permanent financing of the Hydro Transaction. The bonds are secured by our electric and natural gas assets in Montana.

As of December 31, 2014, we are in compliance with our financial debt covenants.

### *Other Long-Term Debt*

During 2014 we entered into a New Market Tax Credit (NMTC) financing agreement, pursuant to Section 45D of the Internal Revenue Code of 1986 as amended, to take advantage of a tax credit program related to the development and construction of a new office building in Butte, Montana. This financing agreement was structured with unrelated third party financial institutions (the Investor) and their wholly-owned community development entities (CDEs) in connection with our participation in qualified transactions under the NMTC program. Upon closing of this transaction, we entered into two loans totaling \$27.0 million payable to the CDEs sponsoring the project, and provided an \$18.2 million investment. The loans have a term of thirty years with an interest rate of approximately 1.146%. In exchange for substantially all of the benefits derived from the tax credits, the Investor contributed approximately \$8.8 million to the project. The NMTC is subject to recapture for a period of seven years. If the expected tax benefits are delivered without risk of recapture to the Investor and our performance obligation is relieved, we expect \$7.9 million of the loan to be forgiven in July 2021. If we do not meet the conditions for loan forgiveness, we would be required to repay \$27.0 million and would concurrently receive the return of our \$18.2 million investment. As we are the primary beneficiary of the entities created in relation to the NMTC transaction, they have been consolidated as variable interest entities. The loans of \$27.0 million are recorded in long-term debt and the investment of \$18.2 million is recorded in Other Investments in the Balance Sheets.

### **Maturities of Long-Term Debt**

The aggregate minimum principal maturities of long-term debt, during the next five years are zero in 2015, \$150.0 million in 2016, zero in 2017, \$55.0 million in 2018 and \$250.0 million in 2019.

### **(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,	
	2014	2013
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	\$ 327	\$ 130
Risk Partners Assurance, Ltd.	18	18
	\$ 345	\$ 148
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	\$ 1,466	\$ 1,420

### **(15) Income Taxes**

Our effective tax rate typically 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.



The income tax benefit for 2014 reflects the release of approximately \$12.6 million of unrecognized tax benefits, including approximately \$0.4 million of accrued interest and penalties due to the lapse of statutes of limitation in the third quarter of 2014.

In September 2013, the IRS issued final tangible property regulations, which included guidance on a safe harbor method for determining the tax treatment of repair costs related to electric transmission and distribution property. The regulations were effective January 1, 2014. During the third quarter of 2014, we elected the safe harbor method and recorded an income tax benefit of approximately \$4.3 million for the cumulative adjustment for years prior to 2014, which is included in the prior year permanent return to accrual adjustment in the table above.

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,	
	2014	2013
Pension / postretirement benefits	\$ 51,817	\$ 20,522
NOL carryforward	42,787	16,758
Unbilled revenue	19,863	18,136
Compensation accruals	17,315	10,409
Customer advances	11,817	10,781
AMT credit carryforward	10,357	10,357
Environmental liability	8,968	9,026
Production tax credit	6,452	3,171
Interest rate hedges	6,251	—
QF obligations	2,162	2,066
Reserves and accruals	2,102	12,097
Property taxes	879	794
Regulatory liabilities	975	659
Regulatory assets	—	7,248
Other, net	4,442	2,992
<b>Deferred Tax Asset</b>	<b>186,187</b>	<b>125,016</b>
Excess tax depreciation	(351,823)	(304,402)
Goodwill amortization	(137,090)	(122,798)
Flow through depreciation	(103,677)	(79,016)
Regulatory assets	(21,394)	—
Reserves and accruals	(330)	—
<b>Deferred Tax Liability</b>	<b>(614,314)</b>	<b>(506,216)</b>
<b>Deferred Tax Liability, net</b>	<b>\$ (428,127)</b>	<b>\$ (381,200)</b>

At December 31, 2014 we estimate our total federal NOL carryforward to be approximately \$351 million prior to consideration of unrecognized tax benefits. 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; \$13.3 million in 2033 and \$74.9 million in 2034. We estimate our state NOL carryforward as of December 31, 2014 is approximately \$264.0 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; \$10.5 million in 2020 and \$59.7 million in 2021. 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):

	2014	2013
Unrecognized Tax Benefits at January 1	\$ 113,466	\$ 113,291
Gross increases - tax positions in prior period	—	—
Gross decreases - tax positions in prior period	—	—
Gross increases - tax positions in current period	909	518
Gross decreases - tax positions in current period	(5,597)	(343)
Lapse of statute of limitations	(12,849)	—
Unrecognized Tax Benefits at December 31	\$ 95,929	\$ 113,466

Our unrecognized tax benefits include approximately \$62.4 million and \$79.0 million related to tax positions as of December 31, 2014 and 2013, respectively, that if recognized, would impact our annual effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. As discussed above, during the year ended December 31, 2014, we released approximately \$0.4 million of accrued interest in the Statements of Income. As of December 31, 2014, we do not have any amounts accrued in the Balance Sheets. 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 had \$0.4 million of interest accrued in the Balance Sheets.

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,					
	2014			2013		
	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount
Foreign currency translation adjustment	\$ 265	\$ —	\$ 265	\$ 166	—	\$ 166
Reclassification of net gains on derivative instruments	(1,110)	426	(684)	(1,188)	458	(730)
Realized loss on cash flow hedging derivatives	(18,388)	7,243	(11,145)	—	—	—
Pension and postretirement medical liability adjustment	134	(52)	82	1,568	(605)	963
Other comprehensive income (loss)	\$ (19,099)	\$ 7,617	\$ (11,482)	\$ 546	\$ (147)	\$ 399

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

	December 31, 2014	December 31, 2013
Foreign currency translation	\$ 797	\$ 532
Derivative instruments designated as cash flow hedges	(8,316)	3,513
Pension and postretirement medical plans	(1,247)	(1,329)
Accumulated other comprehensive income	(8,766)	2,716

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

December 31, 2014					
Twelve Months Ended					
	Affected Line Item in the Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		\$ 3,513	\$ (1,329)	\$ 532	\$ 2,716
Other comprehensive (loss) income before reclassifications		(11,145)	—	265	\$ (10,880)
Amounts reclassified from accumulated other comprehensive income	Interest on long-term	(684)	—	—	\$ (684)
Amounts reclassified from accumulated other comprehensive income		—	82	—	\$ 82
Net current-period other comprehensive (loss) income		(11,829)	82	265	(11,482)
Ending balance		\$ (8,316)	\$ (1,247)	\$ 797	\$ (8,766)

December 31, 2013					
Twelve Months Ended					
	Affected Line Item in the Statements of Income	Interest Rate 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	(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

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2014 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2015	1,996
2016	1,484
2017	671
2018	70
2019	61

Lease and rental expense incurred was \$2.2 million and \$2.0 million for the years ended December 31, 2014 and 2013, 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,	
	2014	2013	2014	2013
<b>Change in Benefit Obligation:</b>				
Obligation at beginning of period	\$ 567,866	\$ 609,643	\$ 30,084	\$ 34,040
Service cost	10,830	13,465	465	541
Interest cost	26,147	22,719	859	877
Actuarial loss (gain)	107,023	(54,671)	958	(3,156)
Settlements	—	—	690	—
Benefits paid	(23,422)	(23,290)	(3,052)	(2,218)
Benefit obligation at end of period	\$ 688,444	\$ 567,866	\$ 30,004	\$ 30,084
<b>Change in Fair Value of Plan Assets:</b>				
Fair value of plan assets at beginning of period	\$ 516,352	\$ 472,936	\$ 18,183	\$ 15,893
Return on plan assets	52,921	55,006	1,391	2,662
Employer contributions	10,200	11,700	1,518	1,846
Benefits paid	(23,422)	(23,290)	(3,052)	(2,218)
Fair value of plan assets at end of period	\$ 556,051	\$ 516,352	\$ 18,040	\$ 18,183
Funded Status	\$ (132,393)	\$ (51,514)	\$ (11,964)	\$ (11,901)
<b>Amounts recognized in the balance sheet consist of:</b>				
Current liability	—	—	(1,169)	(1,178)
Noncurrent liability	(132,393)	(51,514)	(10,795)	(10,723)
Net amount recognized	\$ (132,393)	\$ (51,514)	\$ (11,964)	\$ (11,901)
<b>Amounts recognized in regulatory assets consist of:</b>				
Prior service (cost) credit	(502)	(748)	17,098	19,247
Net actuarial loss	(153,268)	(71,777)	(4,945)	(4,807)
<b>Amounts recognized in AOCI consist of:</b>				
Prior service cost	—	—	(1,151)	(1,302)
Net actuarial gain	—	—	(409)	(971)
Total	\$ (153,770)	\$ (72,525)	\$ 10,593	\$ 12,167

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,	
	2014	2013
Projected benefit obligation	\$ 688.4	\$ 567.9
Accumulated benefit obligation	685.0	565.0
Fair value of plan assets	556.1	516.4

#### 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,	
	2014	2013	2014	2013
Components of Net Periodic Benefit Cost				
Service cost	\$ 10,830	\$ 13,465	\$ 465	\$ 541
Interest cost	26,147	22,719	859	877
Expected return on plan assets	(29,506)	(32,491)	(981)	(1,019)
Amortization of prior service cost (credit)	246	246	(1,998)	(1,998)
Recognized actuarial loss	2,118	11,648	348	1,271
Settlement loss recognized	—	—	690	—
Net Periodic Benefit Cost (Credit)	\$ 9,835	\$ 15,587	\$ (617)	\$ (328)

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 2015 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service credit (cost)	\$ (246)	\$ 1,998
Accumulated loss	(10,470)	(325)

#### Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2014 and 2013. 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 2014 and 2013, 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. The decrease in discount rate during 2014 increased our projected benefit obligation by approximately \$73.6 million.

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. Based on the target asset allocation for our pension assets and future expectations for asset returns, we are keeping our long term rate of return on assets assumption at 5.80% for 2015.

During 2014, we also updated our mortality assumptions to adopt the Society of Actuaries mortality table (RP-2014) and mortality projection scale (MP-2014) released in October 2014. This change in mortality assumption increased our projected benefit obligation by approximately \$33.8 million.

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2014	2013	2014	2013
Discount rate	3.75-3.90 %	4.55-4.75 %	3.20-3.40 %	3.75-4.20 %
Expected rate of return on assets	5.80	7.00	5.80	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 2014 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,	
	2014	2013	2014	2013
Domestic debt securities	55.0%	60.0%	40.0%	40.0%
International debt securities	5.0	5.0	—	—
Domestic equity securities	34.0	30.0	50.0	50.0
International equity securities	6.0	5.0	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,	
	2014	2013	2014	2013	2014	2013
Cash and cash equivalents	—%	—%	0.1%	0.1%	0.2%	1.8%
Domestic debt securities	56.0	58.6	65.6	64.7	37.2	38.6
International debt securities	4.4	4.9	4.5	4.9	—	0.3
Domestic equity securities	34.1	31.4	25.1	25.3	53.9	50.1
International equity securities	5.5	5.1	4.7	5.0	8.7	9.2
	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, 2014, 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
<b>Pension Plan Assets</b>				
Cash and cash equivalents	\$ 126	\$ —	\$ 126	\$ —
Equity securities: (1)				
US small/mid cap growth	16,605	—	16,605	—
US small/mid cap value	15,264	—	15,264	—
US large cap growth	48,560	—	48,560	—
US large cap value	48,785	—	48,785	—
US large cap passive	54,775	—	54,775	—
Non-US core	22,634	—	22,634	—
Emerging markets	7,650	—	7,650	—
Fixed income securities: (2)				
US core	23,177	—	23,177	—
US passive	12,269	—	12,269	—
Long duration	41,451	—	41,451	—
Long duration investment grade	52,767	—	52,767	—
Long duration passive	41,475	—	41,475	—
Opportunistic	5,692	—	5,692	—
Non-US passive	24,504	—	24,504	—
Active long corporate	133,160	—	133,160	—
Participating group annuity contract	7,157	—	7,157	—
	<u>\$ 556,051</u>	<u>\$ —</u>	<u>\$ 556,051</u>	<u>\$ —</u>
<b>Other Postretirement Benefit Plan Assets</b>				
Cash and cash equivalents	\$ 44	\$ —	\$ 44	\$ —
Equity securities: (1)				
US small/mid cap growth	752	—	752	—
US small/mid cap value	721	—	721	—
S&P 500 index	8,234	—	8,234	—
US large cap growth	6	—	6	—
US large cap value	6	—	6	—
US large cap passive	7	—	7	—
Non-US core	1,495	—	1,495	—
Emerging markets	72	—	72	—
Fixed income securities: (2)				
Passive bond market	1,992	—	1,992	—
US core	4,435	—	4,435	—
US passive	1	—	1	—
Long duration	5	—	5	—
Long duration investment grade	6	—	6	—
Long duration passive	5	—	5	—
Opportunistic	240	—	240	—
Non-US passive	3	—	3	—
Active long corporate	16	—	16	—
	<u>\$ 18,040</u>	<u>\$ —</u>	<u>\$ 18,040</u>	<u>\$ —</u>

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
<b>Pension Plan Assets</b>				
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	—
	<b>\$ 516,352</b>	<b>\$ —</b>	<b>\$ 516,352</b>	<b>\$ —</b>
<b>Other Postretirement Benefit Plan Assets</b>				
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	—
	<b>\$ 18,183</b>	<b>\$ —</b>	<b>\$ 18,183</b>	<b>\$ —</b>

- (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 2015 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 for 2014 and 2013 was based on actual contributions to the plan, while 2012 pension expense was calculated using the average of our actual and estimated funding amounts from 2005 through 2012. Annual contributions to each of the pension plans are as follows (in thousands):

	2014	2013
NorthWestern Energy Pension Plan (MT)	\$ 9,000	\$ 10,500
NorthWestern Pension Plan (SD)	1,200	1,200
	<u>\$ 10,200</u>	<u>\$ 11,700</u>

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

	Pension Benefits	Other Postretirement Benefits
2015	\$ 27,652	\$ 3,516
2016	29,905	3,516
2017	31,172	3,387
2018	33,142	3,282
2019	34,660	3,026
2020-2024	194,065	11,923

### 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, 2014 and 2013 were \$8.7 million and \$7.8 million.

## (19) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. In 2014, an additional 600,000 shares of common stock were authorized by the shareholders for issuance under the ECP. As of December 31, 2014, there were 1,124,798 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.

### Performance Share Awards

Performance share awards are granted annually under the ECP. 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. For our outstanding performance share awards which were granted in 2012 and 2013, the performance goals 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. For the awards granted in 2014, our Board added an earnings per share metric and removed the net income metric, while retaining the average return on equity and TSR metrics.

Fair value is determined for each component of the performance share awards. The fair value of the net income / earnings per share 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 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:

	2014	2013
Risk-free interest rate	0.67%	0.44%
Expected life, in years	3	3
Expected volatility	15.5% to 23.3%	16.3% to 25.4%
Dividend yield	3.3%	3.9%

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, 2014, are as follows:

	Performance Share Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	173,646	\$ 29.14
Granted	96,193	38.33
Vested	(84,652)	25.19
Forfeited	(4,615)	33.55
Remaining nonvested grants	180,572	\$ 35.77

We recognized compensation expense of \$3.1 million and \$2.4 million for the years ended December 31, 2014 and 2013, respectively, and a related income tax benefit of \$0.1 million and \$1.5 million, for the years ended December 31, 2014 and 2013, respectively. As of December 31, 2014, we had \$3.6 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 2.0 years. The total fair value of shares vested was \$2.1 million and \$2.2 million for the years ended December 31, 2014 and 2013, 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, 2014, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value	
Beginning nonvested grants	26,628	\$	30.24
Granted	15,092		43.79
Vested	—		—
Forfeited	—		—
Remaining nonvested grants	41,720	\$	35.14

#### 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, 2014 and 2013, DSUs issued to members of our Board totaled 26,460 and 33,837, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2014 and 2013 was approximately \$2.3 million and \$3.6 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, 2,865,957 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.

*Hydro Transaction Issuance* - In November 2014, we issued 7,766,990 shares of our common stock at \$51.50 per share, for aggregate net proceeds of \$386 million.

*Equity Distribution Agreement* - In April 2012, we entered into an Equity Distribution Agreement pursuant to which we could offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to \$100 million. During the first quarter of 2014, we issued 295,979 shares of our common stock at an average price of \$45.65 per share, for net proceeds of \$13.4 million, which are net of sales commissions of approximately \$147,000 and other fees. This concluded our sales pursuant to the Equity Distribution Agreement. Total shares issued under the Equity Distribution Agreement were 2,492,889 shares at an average price of \$40.11, for net proceeds of \$98.7 million.

**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 23,630 and 34,552 during the years ended December 31, 2014 and 2013, respectively, and are reflected in reacquired capital stock. These shares were credited to reacquired capital 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 \$1.0 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately \$0.8 billion through 2029. The present value of the remaining QF liability is recorded in our Balance Sheets as an accumulated miscellaneous operating provision. The following summarizes the change in the QF liability (in thousands):

	December 31,	
	2014	2013
Beginning QF liability	\$ 136,448	\$ 136,652
Unrecovered amount	(10,128)	(10,647)
Interest expense	10,573	10,443
Ending QF liability	\$ 136,893	\$ 136,448

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

	Gross Obligation	Recoverable Amounts	Net
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
2019	77,791	59,020	18,771
Thereafter	646,783	508,195	138,588
Total	\$ 1,015,088	\$ 797,191	\$ 217,897

### 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 27 years. Costs incurred under these contracts were approximately \$402.3 million and \$379.4 million for the years ended December 31, 2014 and 2013, respectively. As of December 31, 2014, our commitments under these contracts are \$206.5 million in 2015, \$161.1 million in 2016, \$134.9 million in 2017, \$107.3 million in 2018, \$103.5 million in 2019, and \$922.7 million thereafter. These commitments are not reflected in our Financial Statements.

### Hydroelectric License Commitments

With the Hydro Transaction, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately \$26.0 million between 2015 and 2040.

### Environmental Matters

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 \$26.4 million to \$35.0 million, primarily for manufactured gas plants discussed below. As of December 31, 2014, we have a reserve of approximately \$29.7 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 \$22.4 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 \$10.8 million, and we estimate that approximately \$8.0 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. We are currently working independently to fully characterize the nature and extent of potential impacts associated with these Nebraska 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, the Title V operating permit programs and the New Source Performance Standards (NSPS).

In January, 2014, the EPA republished NSPS specifying permissible levels of GHG emissions for newly-constructed fossil fuel-fired electric generating units and in June 2014 proposed performance standards for modified and reconstructed power plants. Also in June, 2014, the EPA proposed the Clean Power Plan (CPP) rule to control carbon dioxide emissions from existing fossil fuel fired electric generating units. The rule proposes the establishment of statewide GHG emission standards for individual states based on the state's potential to shift generation to existing natural gas combined cycle plants, to develop new renewable energy, to achieve demand-side management savings, and to improve performance at existing coal-fired units. Under the proposed CPP, States would be required to submit individual plans for achieving GHG emission standards to EPA by summer, 2016, although under certain circumstances additional time to summer, 2018, would be permitted. The initial performance period for compliance would commence in 2020, with full implementation by 2030. The EPA has indicated that it intends to issue final rules on the NSPS, the performance standards for modified and reconstructed plants and the CPP by midsummer, 2015.

On June 23, 2014, the U.S. Supreme Court struck down the EPA's Tailoring Rule, which limited the sources subject to GHG permitting requirements to the largest fossil-fueled power plants, indicating that EPA had exceeded its authority under the Clean Air Act by "rewriting unambiguous statutory terms." However, the decision affirmed EPA's ability to regulate GHG emissions from sources already subject to regulation under the PSD program, which includes most electric generating units.

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

**Coal Combustion Residuals (CCRs)** - In December 2014, the EPA issued a final rule regulating the disposal and management of CCRs as a solid waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and scrubber wastes. The rule imposes some additional recordkeeping and operating requirements, but does not regulate the beneficial use of CCRs. We continue to review the potential costs of complying with the new CCR rule and cannot currently estimate such costs. Legal challenges to the final rule and EPA's determination that CCR is not a hazardous waste are expected and legislation has been introduced in Congress to regulate coal ash. We cannot predict at this time the final outcome of any appeal of the CCR regulations or legislation and what impact, if any, they would have on us.

**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 technology available (BTA)" for minimizing environmental impacts. In May, 2014, the EPA issued a final rule applicable to facilities that withdraw at least 2 million gallons per day of cooling water from waters of the US and use at least 25 percent of the water exclusively for cooling purposes. The final rule gives options for meeting BTA, and provides a flexible compliance approach. In August 2014, EPA published the final rule establishing national requirements applicable to cooling water intake structures, which became effective in October, 2014. Under the rule, permits required for existing facilities will be developed by the individual states and additional capital and/or increased operating costs may be required to comply with future water permit requirements. Challenges to the final cooling water intake rule have been filed by industry groups and by environmental groups in various appellate courts.

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 reviewing public comments on 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 is under a modified consent decree to take final action by September 30, 2015. 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 by April 2015, unless a one year extension is granted on a case-by-case basis. In April 2014, the U.S. Court of Appeals for the D.C. Circuit upheld the MATS rule. The decision was appealed by 23 states and industry groups to the Supreme Court, and in November, 2014 the Court agreed to hear the case. Oral argument will likely be scheduled for the spring and the Supreme Court is expected to issue a ruling by June, 2015.

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 (NO<sub>x</sub>) and sulfur dioxide (SO<sub>2</sub>) were to be required in certain states beginning in 2012. In April 2014 the Supreme Court reversed and remanded the 2012 decision of the U.S. Court of Appeals for the D.C. Circuit that had vacated the CSAPR. Litigation of the remaining CSAPR lawsuits continues, with briefings and oral argument set for 2015.

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, PPL Montana, the operator of Colstrip, as well as environmental groups (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. The Ninth Circuit held oral argument on the petition on May 16, 2014, but no decision has been issued and 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 SO<sub>2</sub>, NO<sub>x</sub> and particulate emissions as expeditiously as practicable, but no later than

five years after the EPA's approval of the SIP. The estimated total project cost for the AQCS at the Big Stone plant is approximately \$384 million (our share is 23.4%). As of December 31, 2014, we have capitalized costs of approximately \$71.8 million related to this project, which is expected to be operational by the end of 2015.

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 SDPUC 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, installed a scrubber, a baghouse, activated carbon injection and a selective non-catalytic reduction system to comply with national ambient air quality standards and the MATS. The project was substantially completed in 2013.

*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 (Court) against the six individual owners of Colstrip, including us, as well as the operator or managing agent of the station (Defendants). 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 dropped claims associated with projects completed before 2001, the Title V claims and the opacity claims. The Amended Complaint alleged a total of 23 claims covering 64 projects.

In the Amended Complaint, Plaintiffs identified physical changes made at Colstrip between 2001 and 2012, that Plaintiffs allege (a) have increased emissions of SO<sub>2</sub>, NO<sub>x</sub> and particulate matter and (b) were “major modifications” subject to permitting requirements under the Clean Air Act. They also alleged violations of the requirements related to Part 70 Operating Permits.

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.

On September 12, 2013, Plaintiffs filed a motion for partial summary judgment as to the applicable method for calculating emissions increases from modifications.

The parties filed a joint notice (Notice) on April 21, 2014 that advised the Court of Plaintiffs’ intent to file a Second Amended Complaint which dropped claims relating to 52 projects, and added one additional project. At the joint request of the parties, the Court extended various deadlines set a bench trial date for the liability portion of the case for June 8, 2015.

On May 6, 2014, the Court held oral argument on Defendants’ motion to dismiss and on Plaintiffs’ motion for summary judgment on the applicable legal standard. On May 22, 2014, the Magistrate issued findings and recommendations, which denied Plaintiffs’ motion for summary judgment and denied most of the Colstrip owners’ motion to dismiss, but dismissed seven of Plaintiffs’ “best available control technology” claims and dismissed two of Plaintiffs’ claims for injunctive relief. The Plaintiffs filed an objection to the Magistrate’s findings and recommendations with the U.S. Federal District Court Judge, and on August 13, 2014, the Court adopted the Magistrate’s findings and conclusions.

On August 27, 2014, the Plaintiffs filed their Second Amended Complaint, which alleges a total of 13 claims covering eight projects and seeks 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. Defendants filed their Answer to the Second Amended Complaint on September 26, 2014. Since filing the Second Amended Complaint, Plaintiffs have indicated that they are no longer pursuing a number of claims and projects thereby reducing their total claims to eight relating to four projects. A bench trial is scheduled for November 16, 2015.

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.

### Billings Refinery Outage Claim

In August 2014, we received a demand letter from a refinery in Billings claiming that it had sustained damages of approximately \$48.5 million as a result of a January 2014 electrical outage. We dispute the claim and intend to vigorously

defend against it. We reported the refinery's claim to our insurance carrier under our primary insurance policy, which has a \$2.0 million retention. This matter is in the initial stages and we cannot predict an outcome or estimate the amount or range of loss, if any, that would be associated with an adverse result.

### **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 - ELECTRIC					
	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	<b>Intangible Plant</b>					
3	301 Organization	\$ 19,995	\$ -	\$ 19,995	\$19,995	0.00%
4	302 Franchises and Consents	2,004	-	2,004	2,004	0.00%
5	303 Miscellaneous Intangible Plant	7,394,194	-	7,394,194	4,815,642	53.55%
6	<b>Total Intangible Plant</b>	7,416,193	-	7,416,193	4,837,641	53.30%
7						
8	<b>Production Plant</b>					
9						
10	<b>Steam Production</b>					
11	310 Land and Land Rights	-	-	-	-	-
12	311 Structures and Improvements	-	-	-	-	-
13	312 Boiler Plant Equipment	-	-	-	-	-
14	313 Engines, Engine Driven Generator	-	-	-	-	-
15	314 Turbogenerator Units	-	-	-	-	-
16	315 Accessory Electric Equipment	-	-	-	-	-
17	316 Misc. Power Plant Equipment	416,717,131	-	416,717,131	420,662,087	-0.94%
18	<b>Total Steam Production Plant</b>	416,717,131	-	416,717,131	420,662,087	-0.94%
19						
20	<b>Nuclear Production</b>					
21	320 - 325 Not Applicable	-	-	-	-	-
22	<b>Total Nuclear Production Plant</b>	-	-	-	-	-
23						
24	<b>Hydraulic Production</b>					
25	330 Land and Land Rights	5,787,621	-	5,787,621	-	-
26	331 Structures and Improvements	123,105,566	-	123,105,566	-	-
27	332 Reservoirs, Dams and Waterways	132,384,175	-	132,384,175	-	-
28	333 Water Wheel, Turbine, Generators	104,216,181	-	104,216,181	-	-
29	334 Accessory Electric Equipment	78,135,731	-	78,135,731	-	-
30	335 Misc. Power Plant Equipment	36,525,062	-	36,525,062	-	-
31	336 Roads, Railroads and Bridges	2,349,226	-	2,349,226	-	-
32	<b>Total Hydraulic Production Plant</b>	482,503,562	-	482,503,562	-	-
33						
34	<b>Other Production</b>					
35	340 Land and Land Rights	160,028		160,028	441,907	(0.64)
36	341 Structures and Improvements	28,955,026	19,232	28,935,794	47,807,712	(0.39)
37	342 Fuel Holders & Accessories	12,432,137	112,084	12,320,053	12,320,053	0.00%
38	343 Prime Movers	-	-	-	-	-
39	344 Generators	46,801,657	2,247,016	44,554,641	28,411,518	>300.00%
40	345 Accessory Electric Equipment	6,662,818	302,333	6,360,485	2,903,668	>300.00%
41	346 Misc. Power Plant Equipment	164,834,324	7,268	164,827,056	164,385,874	0.27%
42	<b>Total Other Production Plant</b>	259,845,990	2,687,933	257,158,057	256,270,732	0.35%
43	<b>Total Production Plant</b>	1,159,066,683	2,687,933	1,156,378,750	676,932,819	70.83%

MONTANA PLANT IN SERVICE - ELECTRIC						
	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	<b>Transmission Plant</b>					
3	350 Land and Land Rights	27,842,575	-	27,842,575	22,154,682	25.67%
4	352 Structures and Improvements	26,498,470	-	26,498,470	25,926,202	2.21%
5	353 Station Equipment	202,020,602	-	202,020,602	190,227,487	6.20%
6	354 Towers and Fixtures	28,732,934	-	28,732,934	28,733,308	0.00%
7	355 Poles and Fixtures	181,870,879	879,055	180,991,824	167,419,901	8.11%
8	356 Overhead Conductors & Devices	142,571,138	699,371	141,871,767	140,930,399	0.67%
9	357 Underground Conduit	137,878	102,286	35,592	35,592	0.00%
10	358 Undergrnd Conductors & Devices	1,410,535	554,036	856,499	856,499	0.00%
11	359 Roads and Trails	2,519,641	44,906	2,474,735	2,474,735	0.00%
12	<b>Total Transmission Plant</b>	<b>613,604,652</b>	<b>2,279,654</b>	<b>611,324,998</b>	<b>578,758,805</b>	<b>5.63%</b>
13						
14	<b>Distribution Plant</b>					
15	360 Land and Land Rights	5,409,984	601	5,409,383	5,401,810	0.14%
16	361 Structures and Improvements	10,395,921	911,983	9,483,938	9,240,331	2.64%
17	362 Station Equipment	149,204,095	3,024,086	146,180,009	141,224,499	3.51%
18	363 Storage Battery Equipment	-	-	-	-	-
19	364 Poles, Towers, and Fixtures	222,543,130	432,409	222,110,721	196,866,235	12.82%
20	365 Overhead Conductors & Devices	106,447,892	509,444	105,938,448	103,146,089	2.71%
21	366 Underground Conduit	79,925,107	448,110	79,476,997	71,403,529	11.31%
22	367 Undergrnd Conductors & Devices	144,733,774	2,913,704	141,820,070	128,802,835	10.11%
23	368 Line Transformers	193,769,678	836,075	192,933,603	187,619,905	2.83%
24	369 Services	104,582,061	255,411	104,326,650	99,563,217	4.78%
25	370 Meters	52,441,525	96,955	52,344,570	51,480,647	1.68%
26	371 Installations on Cust. Premises	-	-	-	-	-
27	372 Leased Property on Cust. Premises	-	-	-	-	-
28	373 Street Lighting and Signal Systems	53,041,553	19,872	53,021,681	52,614,661	0.77%
29	<b>Total Distribution Plant</b>	<b>1,122,494,720</b>	<b>9,448,650</b>	<b>1,113,046,070</b>	<b>1,047,363,758</b>	<b>6.27%</b>
30						
31	<b>General Plant</b>					
32	389 Land and Land Rights	616,736	-	616,736	515,911	19.54%
33	390 Structures and Improvements	8,921,883	478,086	8,443,797	8,382,257	0.73%
34	391 Office Furniture and Equipment	2,677,643	-	2,677,643	4,782,896	-44.02%
35	392 Transportation Equipment	41,753,718	244,517	41,509,201	39,676,601	4.62%
36	393 Stores Equipment	569,515	-	569,515	597,935	-4.75%
37	394 Tools, Shop & Garage Equipment	6,440,865	7,477	6,433,388	6,286,136	2.34%
38	395 Laboratory Equipment	2,148,283	2,594	2,145,689	2,403,630	-10.73%
39	396 Power Operated Equipment	3,419,233	-	3,419,233	3,206,995	6.62%
40	397 Communication Equipment	17,905,632	1,480,505	16,425,127	17,075,107	-3.81%
41	398 Miscellaneous Equipment	1,995,260	-	1,995,260	140,292	>300.00%
42	399 Other Tangible Equipment	-	-	-	-	-
43	<b>Total General Plant</b>	<b>86,448,768</b>	<b>2,213,179</b>	<b>84,235,589</b>	<b>83,067,760</b>	<b>1.41%</b>
44	<b>Total Plant in Service</b>	<b>2,989,031,016</b>	<b>16,629,416</b>	<b>2,972,401,600</b>	<b>2,390,960,783</b>	<b>24.32%</b>
45						
46	4101 El Plant Allocated from Common	60,384,311	-	60,384,311	56,407,253	7.05%
47	105 El Plant Held for Future Use	3,553,513	-	3,553,513	3,555,655	(0.00)
48	107 El Construction Work in Progress	117,146,542	-	117,146,542	39,555,014	196.16%
49						
50						
51	<b>TOTAL ELECTRIC PLANT</b>	<b>\$ 3,170,115,382</b>	<b>\$ 16,629,416</b>	<b>\$ 3,153,485,966</b>	<b>\$ 2,490,478,705</b>	<b>26.62%</b>



Sch. 19 cont.

**MONTANA PLANT IN SERVICE - ELECTRIC**

	<b>CONSOLIDATED PLANT IN SERVICE</b>	December 31,	
		2014	2013
1			
2	Montana Electric	\$ 2,972,401,600	\$ 2,390,960,783
3	Yellowstone National Park	16,629,416	13,618,264
4	Montana Natural Gas (Includes CMP)	699,769,408	677,024,230
5	Common	93,665,528	86,730,756
6	Townsend Propane	1,519,564	1,519,564
7	South Dakota Electric	597,960,821	580,354,887
8	South Dakota Natural Gas	163,980,215	161,401,195
9	South Dakota Common	49,516,491	47,886,249
10	Asset Retirement Obligation	16,678,342	15,205,199
11	<b>TOTAL PLANT</b>	<b>\$ 4,612,121,385</b>	<b>\$ 3,974,701,127</b>

Sch. 20	MONTANA DEPRECIATION SUMMARY - ELECTRIC						
	Functional Plant Class	Montana Plant Cost	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	Current Avg. Rate
1	Accumulated Depreciation						
2							
3	Steam Production	\$ 420,209,453	\$ 61,469,060	\$ -	\$ 61,469,060	\$ 53,470,852	2.94%
4							
5	Nuclear Production	-	-	-	-	-	-
6							
7	Hydraulic Production	476,715,941	1,191,779	-	1,191,779	-	2.00%
8							
9	Other Production	256,179,341	32,352,823	2,619,603	29,733,220	20,636,648	3.55%
10							
11	Transmission	576,968,101	294,719,635	1,947,534	292,772,101	278,973,290	2.78%
12							
13	Distribution	1,044,201,455	571,426,730	4,716,173	566,710,557	545,602,458	3.13%
14							
15	General and Intangible	87,367,491	48,496,213	299,541	48,196,672	47,877,127	8.08%
16							
17	Common	54,289,135	21,997,266	-	21,997,266	21,111,749	6.01%
18							
19							
20	Total Accum Depreciation	\$ 2,915,930,917	\$ 1,031,653,506	\$ 9,582,851	\$ 1,022,070,655	\$ 967,672,124	3.03%
21							
22							
23							
24	Consolidated	December 31,					
25	Accumulated Depreciation	2014 2013					
26							
27	Montana Electric	\$ 1,000,073,389	\$946,560,375				
28	Yellowstone National Park	9,582,851	9,224,628				
29	Montana Natural Gas (Includes CMP)	267,809,946	250,184,290				
30	Common	34,643,025	33,281,451				
31	Townsend Propane	769,983	729,083				
32	South Dakota Electric	268,707,554	261,015,837				
33	South Dakota Natural Gas	75,774,427	72,029,599				
34	South Dakota Common	15,531,797	13,624,280				
35	Acquisition Writedown	59,503,577	62,208,066				
36	Basin Creek Capital Lease	17,089,022	15,078,542				
37	FIN 47	2,092,675	1,503,510				
38	CWIP-Capital Retirement Clearing	-6,556,494	-6,741,583				
39	Total Consolidated Accum Depreciation	\$1,745,021,750	\$1,658,698,078				

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	151 Fuel Stock	\$ 2,208,383	\$ -	\$ 2,208,383	\$ 2,290,081	100.00%
3						
4	154 Plant Materials & Operating Supplies					
5	Assigned and Allocated to:					
6	Operation & Maintenance	-		-	-	-
7	Construction	-		-	-	-
8	Production Plant	4,383,990		4,383,990	3,977,116	10.23%
9	Transmission Plant	3,016,669		3,016,669	2,371,189	27.22%
10	Distribution Plant	10,815,991		10,815,991	10,126,057	6.81%
11						
12						
13	<b>Total MT Materials and Supplies</b>	<b>\$ 20,425,033</b>	<b>\$ -</b>	<b>\$ 20,425,033</b>	<b>\$ 18,764,443</b>	<b>8.85%</b>
14						
15						
16	<b>Consolidated</b>	<b>December 31,</b>				
17	<b>Fuel Stock</b>	<b>2014</b>	<b>2013</b>			
18						
19	Montana Electric	\$ 2,208,383	\$ 2,290,081			
20	South Dakota	5,421,968	6,170,183			
21						
22	<b>Total Fuel Stock</b>	<b>\$ 7,630,351</b>	<b>\$ 8,460,264</b>			
23						
24						
25						
26	<b>Consolidated</b>	<b>December 31,</b>				
27	<b>Materials and Supplies</b>	<b>2014</b>	<b>2013</b>			
28						
29	Montana Electric	\$ 18,216,650	\$ 16,474,362			
30	Montana Natural Gas	3,019,370	3,035,084			
31	South Dakota	7,846,464	7,281,627			
32						
33	<b>Total Consolidated Materials and Supplies</b>	<b>\$ 29,082,484</b>	<b>\$ 26,791,073</b>			

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC			
	Commission Accepted - Most Recent	% Capital Structure	% Cost Rate	Weighted Cost
1	<b>Regulated Electric Transmission and Distribution Utility</b>			
2				
3				
4				
5				
6				
7				
8	Common Equity	48.00%	10.25%	4.92%
9	Long Term Debt	52.00%	5.76%	3.00%
10				
11	<b>TOTAL</b>	100.00%		7.92%
12	<b>Colstrip Unit 4</b>			
13				
14				
15				
16				
17				
18				
19	Common Equity	50.00%	10.00%	5.00%
20	Long Term Debt	50.00%	6.50%	3.25%
21				
22	<b>TOTAL</b>	100.00%		8.25%
23	<b>Dave Gates Generating Station</b>			
24				
25				
26				
27				
28				
29				
30	Common Equity	50.00%	10.25%	5.13%
31	Long Term Debt	50.00%	6.07%	3.03%
32				
33	<b>TOTAL</b>	100.00%		8.16%
34	<b>Spion-Kop Wind</b>			
35				
36				
37				
38				
39				
40				
41	Common Equity	48.00%	10.00%	4.80%
42	Long Term Debt	52.00%	4.23%	2.20%
43				
44	<b>TOTAL</b>	100.00%		7.00%
45	<b>Hydro Assets</b>			
46				
47				
48				
49				
50				
51				
52	Common Equity	48.00%	9.80%	4.70%
53	Long Term Debt	52.00%	4.25%	2.21%
54				
55	<b>TOTAL</b>	100.00%		6.91%
56				
57				

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	<b>Cash Flows from Operating Activities:</b>			
3	Net Income	\$ 120,686,353	\$ 93,982,666	28.41%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	112,991,164	109,962,010	2.75%
6	Amortization, Net	10,574,124	2,858,210	269.96%
7	Other Noncash Charges to Net Income, Net	12,431,796	9,033,466	37.62%
8	Deferred Income Taxes, Net	(7,411,618)	47,108,947	-115.73%
9	Investment Tax Credit Adjustments, Net	(273,079)	(334,950)	18.47%
10	Change in Operating Receivables, Net	5,776,323	(26,616,918)	121.70%
11	Change in Materials, Supplies & Inventories, Net	761,534	537,664	41.64%
12	Change in Operating Payables & Accrued Liabilities, Net	(1,627,921)	16,651,383	-109.78%
13	Allowance for Funds Used During Construction (AFUDC)	(6,551,852)	(5,049,543)	-29.75%
14	Change in Other Assets & Liabilities, Net	(6,542,680)	(15,444,979)	57.64%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(4,314,407)	(2,416,238)	-78.56%
17	Change in Regulatory Assets	7,306,869	(36,983,179)	119.76%
18	Change in Regulatory Liabilities	3,617,352	(4,719,283)	176.65%
19	<b>Net Cash Provided by Operating Activities</b>	<b>247,423,958</b>	<b>188,569,255</b>	<b>31.21%</b>
20	<b>Cash Inflows/Outflows From Investment Activities:</b>			
21	Construction/Acquisition of Property, Plant and Equipment	(1,172,692,087)	(300,103,374)	-290.76%
22	(Net of AFUDC)			
23	Proceeds from Sale of Assets	1,535,499	3,765,819	-59.23%
24	Other Investing activities	(34,527,780)	-	-
25	<b>Net Cash Used in Investing Activities</b>	<b>(1,205,684,368)</b>	<b>(296,337,555)</b>	<b>&gt;-300.00%</b>
26	<b>Cash Flows from Financing Activities:</b>			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	505,789,025	100,000,000	>300.00%
29	Issuance of Short Term Borrowings, Net	126,890,525	18,015,652	>300.00%
30	Proceeds From Issuance of Common Stock, Net	399,207,125	56,825,170	>300.00%
31	Payments for Retirement of:			
32	Capital Lease Obligations, Net	(89,403)	(148,500)	39.80%
33	Repayments of Short Term Borrowings, Net	-	-	-
34	Dividends on Common Stock	(65,019,105)	(57,683,552)	-12.72%
35	Other Financing Activities:			
36	Debt Financing Costs	(5,247,637)	(7,593,330)	30.89%
37	Treasury Stock Activity	(814,026)	(1,041,694)	21.86%
38	<b>Net Cash (Used in)/Provided by Financing Activities</b>	<b>960,716,504</b>	<b>108,373,746</b>	<b>&gt;300.00%</b>
39	<b>Net (Decrease)/Increase in Cash and Cash Equivalents</b>	<b>2,456,094</b>	<b>605,446</b>	<b>&gt;300.00%</b>
40	<b>Cash and Cash Equivalents at Beginning of Year</b>	<b>10,427,560</b>	<b>9,822,114</b>	<b>6.16%</b>
41	<b>Cash and Cash Equivalents at End of Year</b>	<b>\$ 12,883,654</b>	<b>\$ 10,427,560</b>	<b>23.55%</b>
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 and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.			
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 %
1									
2	<b>First Mortgage Bonds</b>								
3	6.34% Series, Due 2019	03/26/09	04/01/19	\$ 250,000,000	\$ 247,657,313	\$ 249,928,812	6.34%	\$ 16,514,170	6.61%
4	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%
5	6.04% Series, Due 2016	09/13/06	09/01/16	150,000,000	148,302,298	149,987,750	6.04%	9,308,114	6.21%
6	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%
5	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%
6	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%
6	4.85% Series(\$65M), Due 2043	12/19/13	12/19/43	15,000,000	14,929,953	15,000,000	4.85%	730,429	4.87%
7	3.99% Series(\$35M), Due 2028	12/19/13	12/19/43	35,000,000	34,836,556	35,000,000	3.99%	1,409,064	4.03%
8	4.176% Series(\$450M), Due 2044	11/14/14	11/14/44	450,000,000	445,743,514	450,000,000	4.176%	19,548,923	4.34%
9	<b>Total First Mortgage Bonds</b>			\$ 1,216,000,000	\$ 1,205,367,484	\$ 1,215,916,562		\$ 63,484,230	5.22%
10									
11	<b>Pollution Control Bonds</b>								
12	4.65% Series, Due 2023	04/27/06	08/01/23	\$ 170,205,000	\$ 164,451,956	\$ 170,205,000	4.65%	\$ 8,467,855	4.98%
13									
14	<b>Total Pollution Control Bonds</b>			\$ 170,205,000	\$ 164,451,956	\$ 170,205,000		\$ 8,467,855	4.98%
15									
16	<b>Other Long-Term Debt</b>								
17	New Market Tax Credit Financing - New G.O Bldg	07/01/14	07/01/44	\$ 26,976,900	\$ 26,292,348	\$ 26,976,900	1.146%	\$ 333,771	1.24%
18									
19	<b>Total Other Long Term Debt</b>			\$ 26,976,900	\$ 26,292,348	\$ 26,976,900		\$ 333,771	1.24%
20									
21	<b>TOTAL LONG TERM DEBT</b>			\$ 1,413,181,900	\$ 1,396,111,788	\$ 1,413,098,462		\$ 72,285,856	5.12%
22									
23									
24	This schedule does not reflect our capital lease, which is the Basin Creek contract lease. That amount is \$28,162,445.								
25									
26									
27									
28									
29									
30									
31									
32									
33									
34									
35									
36									
37									
38									

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	NOT APPLICABLE									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
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15										
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19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	TOTAL									

Sch. 26		COMMON STOCK							
		Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price		Price/ Earnings Ratio
							High	Low	
1									
2									
3	January	38,749,060	\$27.05				\$45.38	\$42.64	
4									
5	February	38,838,028	27.37				47.05	43.92	
6									
7	March	39,135,645	27.45	\$1.17	\$0.40		47.86	44.77	
8									
9	April	39,136,327	27.59				48.93	46.60	
10									
11	May	39,138,075	27.65				48.49	45.49	
12									
13	June	39,139,365	27.27	0.20	0.40		52.49	47.28	
14									
15	July	39,140,079	27.32				52.70	46.21	
16									
17	August	39,142,044	27.40				48.76	45.24	
18									
19	September	39,143,568	27.63	0.77	0.40		49.55	45.12	
20									
21	October	39,145,513	27.72				53.45	45.14	
22									
23	November	46,913,400	31.26				54.42	51.40	
24									
25	December	46,914,811	31.50	0.87	0.40		58.70	52.02	
26									
27	TOTAL Year End	40,156,177	\$31.50	\$3.01	\$1.60	46.84%	\$56.58		18.8
28									
29									
30	1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average								
31	shares for the twelve months ended December 31, 2014.								
32									
33									
34									
35									
36									



Sch. 27	MONTANA EARNED RATE OF RETURN - ELECTRIC			
	Description	This Year	Last Year	% Change
1	<b>Rate Base</b>			
2	101 Plant in Service	\$2,613,915,606	\$2,399,297,321	8.95%
3	108 Accumulated Depreciation	(999,214,380)	(953,312,704)	-4.81%
4				
5	<b>Net Plant in Service</b>	<b>\$1,614,701,226</b>	<b>\$1,445,984,617</b>	<b>11.67%</b>
6	Additions:			
7	154, 156 Materials & Supplies	\$14,241,167	\$13,626,911	4.51%
8	165 Prepayments			
9	Other Additions <u>1/</u>	147,864,538	119,045,247	24.21%
10				
11	<b>Total Additions</b>	<b>\$162,105,705</b>	<b>\$132,672,158</b>	<b>22.19%</b>
12	Deductions:			
13	190 Accumulated Deferred Income Taxes	\$272,701,978	\$223,503,359	22.01%
14	252 Customer Advances for Construction	22,758,364	25,795,663	-11.77%
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions	35,432,738	31,260,260	13.35%
17				
18	<b>Total Deductions</b>	<b>\$330,893,080</b>	<b>\$280,559,282</b>	<b>17.94%</b>
19	<b>Total Rate Base</b>	<b>\$1,445,913,851</b>	<b>\$1,298,097,493</b>	<b>11.39%</b>
20	<b>Net Earnings</b>	<b>\$ 122,440,308</b>	<b>\$ 101,947,470</b>	<b>20.10%</b>
21	<b>Rate of Return on Average Rate Base</b>	<b>8.468%</b>	<b>7.854%</b>	<b>7.82%</b>
22	<b>Rate of Return on Average Equity <u>2/</u></b>	<b>11.334%</b>	<b>9.671%</b>	<b>17.20%</b>
23				
24	<b>Major Normalizing and</b>			
25	<b>Commission Ratemaking Adjustments</b>			
26	Rate Schedule Revenues	(\$146,710)	(\$123,026)	-19.25%
27	DSM Lost Revenues <u>4/</u>	-	(1,875,674)	100.00%
28	Income Tax from 2013 and prior <u>3/</u>	(3,729,470)		
29				
30	Non-Allowables:			
31	Advertising	527,288	494,673	6.59%
32	Dues, Contributions, Other	99,844	97,936	1.95%
33				
34	Associated Income Taxes <u>5/</u>	(127,233)	(302,334)	57.92%
35				
36	<b>Total Adjustments</b>	<b>(\$3,376,282)</b>	<b>(\$1,708,424)</b>	<b>-97.63%</b>
37	<b>Revised Net Earnings</b>	<b>\$119,064,026</b>	<b>\$100,239,045</b>	<b>18.78%</b>
38	Rate Base Adjustment			
39	Stipulation with MCC <u>6/</u>	(\$21,667,666)	(\$22,533,333)	3.84%
40				
41	<b>Revised Rate Base</b>	<b>\$1,424,246,185</b>	<b>\$1,275,564,160</b>	<b>11.66%</b>
42	<b>Adjusted Rate of Return on Average Rate Base</b>	<b>8.360%</b>	<b>7.858%</b>	<b>6.38%</b>
43	<b>Adjusted Rate of Return on Average Equity <u>2/</u></b>	<b>11.007%</b>	<b>9.705%</b>	<b>13.42%</b>
44				
45	1/ Other additions includes a FAS 109 Regulatory Asset that provides an offset to the accumulated			
46	deferred taxes.			
47				
48	2/ Return on Equity calculated using the capital structure approved in Docket No. D2009.9.129,			
49	Docket No. D2008.6.69, Docket No. D2008.8.95, and Docket No. D2011.5.41.			
50				
51	3/ Income tax related to repairs deduction for years prior to 2014.			
52				
53	4/ Demand-side management lost revenue was adjusted to normalize out balances related to prior periods.			
54				
55	5/ Associated income taxes include an interest synchronization adjustment based upon the approved			
56	capital structure in Docket No. D2009.9.129, Docket No. D2008.6.69, Docket No. D2008.8.95 and Docket			
57	No. D2011.5.41.			
58				
59	6/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting two-thirds of the \$38.8 million			
60	allocated to electric as a rate base reduction.			
61				
62				

Sch. 27	cont.	MONTANA EARNED RATE OF RETURN - ELECTRIC		
	Description	This Year	Last Year	% Change
1				
2	<b>Detail - Other Additions</b>			
3	FAS 109 Regulatory Asset	\$141,187,188	\$112,135,268	25.91%
4	Cost of Refinancing Debt	4,593,017	5,124,344	-10.37%
5	Fuel Stock	2,084,333	1,785,635	16.73%
6				-
7				
8	<b>Total Other Additions</b>	<b>\$147,864,538</b>	<b>\$119,045,247</b>	<b>24.21%</b>
9				
10	<b>Detail - Other Deductions</b>			
11	Personal Injury and Property Damage	\$5,492,439	\$6,078,606	-9.64%
12	Gross Cash Requirements	29,940,299	25,181,654	18.90%
13	MPSC/MCC Taxes	-	-	-
14				
15				
16	<b>Total Other Deductions</b>	<b>\$35,432,738</b>	<b>\$31,260,260</b>	<b>13.35%</b>
17				
18				
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42				

Schedule 27A

Sch. 28	MONTANA COMPOSITE STATISTICS - ELECTRIC (EXCLUDES YNP)		
	Description		Amount
1			
2		<b>Plant (Intrastate Only)</b>	
3			
4	101	Plant in Service (Includes Allocation from Common)	\$ 3,032,785,911
5	105	Plant Held for Future Use	3,553,513
6	107	Construction Work in Progress	117,146,542
7	114	Plant Acquisition Adjustments	350,132,657
8	151-163	Materials & Supplies	20,425,033
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	1,023,007,657
11	252	Contributions in Aid of Construction	23,811,043
12	<b>NET BOOK COSTS</b>		2,477,224,956
13			
14		<b>Revenues &amp; Expenses</b>	
15			
16	400	Operating Revenues	780,678,190
17			
18	<b>Total Operating Revenues</b>		780,678,190
19			
20	401-402	Other Operating Expenses (including regulatory amortizations)	491,366,501
21	403-407	Depreciation & Amortization Expenses	83,148,708
22	408.1	Taxes Other than Income Taxes	84,188,473
23	409-411	Federal & State Income Taxes	(465,793)
24	411.8	SO2 Allowances	(7)
25			
26	<b>Total Operating Expenses</b>		658,237,882
27	<b>Net Operating Income</b>		122,440,308
28			
29	415-421.1	Other Income	3,011,419
30	421.2-426.5	Other Deductions	653,874
31	<b>NET INCOME BEFORE INTEREST EXPENSE</b>		\$ 124,797,853
32			
33		<b>Average Customers (Intrastate Only)</b>	
34		Residential	283,145
35		Commercial & Industrial	65,138
36		Other (including interdepartmental)	4,117
37			
38	<b>TOTAL AVERAGE NUMBER OF CUSTOMERS</b>		352,400
39			
40		<b>Other Statistics (Intrastate Only)</b>	
41		Average Annual Residential Use (Kwh)	8,471
42		Average Annual Residential Cost per (Kwh)	\$0.107
43		Average Residential Monthly Bill	\$75.72
44			
45		Plant in Service (Gross) per Customer	\$8,606

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,150	479	116	5	600
2	Alberton	420	380	83	12	475
3	Alder	103	212	80	17	309
4	Amsterdam	180	128	37	8	173
5	Anaconda	9,298	4,249	802	47	5,098
6	Armington	-	1	-	-	1
7	Arrow Creek	-	5	5	-	10
8	Augusta	309	253	108	3	364
9	Avon	111	93	63	3	159
10	Barber	-	49	12	-	61
11	Basin	212	159	73	1	233
12	Bearcreek	79	63	19	3	85
13	Belfry	218	185	68	16	269
14	Belgrade	7,389	7,458	1,752	94	9,304
15	Belt	597	635	238	16	889
16	Benchland	-	6	6	-	12
17	Big Sandy	598	337	141	6	484
18	Big Sky	2,308	3,391	803	25	4,219
19	Big Timber	1,641	1,217	403	28	1,648
20	Billings	104,170	46,566	8,144	693	55,403
21	Black Eagle	904	454	163	16	633
22	Bonner	1,663	78	38	1	117
23	Boulder	1,183	828	250	25	1,103
24	Box Elder	87	144	66	10	220
25	Bozeman	37,280	26,892	5,636	370	32,898
26	Brady	140	93	37	3	133
27	Bridger	708	439	164	13	616
28	Broadview	192	226	153	1	380
29	Buffalo	-	-	2	3	5
30	Butte	33,525	14,740	2,530	282	17,552
31	Cameron	-	355	111	8	474
32	Canyon Creek	-	186	40	8	234
33	Carter	58	118	73	3	194
34	Cascade	685	1,106	298	25	1,429
35	Centerville	-	13	11	1	25
36	Checkerboard	-	53	9	1	63
37	Chester	847	483	302	15	800
38	Chinook	1,203	801	310	16	1,127
39	Choteau	1,684	1,004	372	24	1,400
40	Churchill	902	705	143	27	875
41	Clancy	1,661	840	151	9	1,000
42	Clinton	1,052	103	33	2	138
43	Coffee Creek	-	58	23	1	82
44	Colstrip	2,214	972	206	34	1,212
45	Columbus	1,893	1,005	335	18	1,358
46	Conrad	2,570	1,269	476	28	1,773
47	Corbin	-	1	2	-	3
48	Corvallis	976	784	177	37	998
49	Craig	43	95	34	6	135
50	Custer	159	1	3	-	4

Schedule 29

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Darby	720	785	247	19	1,051
2	De Borgia	78	147	33	2	182
3	Deer Lodge	3,111	2,072	584	82	2,738
4	Denton	255	180	83	1	264
5	Dillon	4,134	2,005	537	59	2,601
6	Divide	-	68	14	3	85
7	Dodson	124	112	68	6	186
8	Drummond	309	362	213	28	603
9	Dutton	316	242	123	4	369
10	East Helena	1,984	2,924	401	28	3,353
11	Edgar	114	176	55	8	239
12	Elliston	219	207	62	3	272
13	Ennis	838	1,705	555	41	2,301
14	Fairfield	708	402	159	25	586
15	Florence	765	381	143	15	539
16	Floweree	-	107	57	1	165
17	Fort Belknap	1,293	457	107	26	590
18	Fort Benton	1,464	826	356	30	1,212
19	Fort Harrison	-	-	94	4	98
20	Fromberg	438	311	73	10	394
21	Gallatin Gateway	856	680	178	17	875
22	Gardiner	875	779	289	12	1,080
23	Garrison	96	116	61	6	183
24	Geraldine	261	283	155	2	440
25	Geyser	87	65	36	4	105
26	Gildford	179	92	66	2	160
27	Glasgow	3,250	1,677	702	63	2,442
28	Glasgow Air Base	-	1	-	-	1
29	Gold Creek	-	77	37	3	117
30	Grantsdale	-	27	3	1	31
31	Great Falls	58,505	28,867	5,178	391	34,436
32	Greycliff	112	52	30	9	91
33	Hall	-	262	76	19	357
34	Hamilton	4,348	5,313	1,413	116	6,842
35	Hardin	3,505	1,409	449	27	1,885
36	Harlem	808	432	206	27	665
37	Harlowton	997	678	276	7	961
38	Harrison	137	176	56	29	261
39	Haugan	-	80	36	2	118
40	Havre	10,026	4,893	1,163	186	6,242
41	Helena	53,457	23,977	5,046	423	29,446
42	Hingham	118	107	72	2	181
43	Hinsdale	217	138	51	6	195
44	Hobson	215	164	60	10	234
45	Huson	210	142	35	1	178
46	Inverness	55	41	27	1	69
47	Jardine	57	1	1	-	2
48	Jeffers	-	3	1	-	4
49	Jefferson City	472	306	51	3	360
50	Joliet	595	471	129	18	618

Schedule 29A

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Joplin	157	99	50	2	151
2	Judith Gap	126	87	54	7	148
3	Kremlin	98	69	34	1	104
4	Laurel	6,718	3,177	469	24	3,670
5	Lavina	187	190	99	12	301
6	Lennepe	-	20	11	1	32
7	Lewistown	5,910	3,343	905	53	4,301
8	Lincoln	1,013	1,058	264	16	1,338
9	Livingston	7,044	4,686	1,114	59	5,859
10	Logan	99	59	23	2	84
11	Lohman	-	31	32	5	68
12	Lolo	3,892	1,453	189	17	1,659
13	Loma	85	68	38	3	109
14	Lothair	-	16	10	-	26
15	Malta	1,997	1,327	489	48	1,864
16	Manhattan	1,520	1,083	297	90	1,470
17	Martinsdale	64	128	83	10	221
18	Marysville	80	70	34	2	106
19	Maxville	130	5	-	-	5
20	McAllister	-	216	46	8	270
21	Melrose	-	1	-	-	1
22	Melstone	96	164	282	17	463
23	Melville	-	71	55	4	130
24	Milltown	-	77	18	3	98
25	Missoula	66,788	35,651	6,385	621	42,657
26	Moccasin	-	45	34	2	81
27	Molt	-	27	31	-	58
28	Monarch	-	328	56	4	388
29	Montana City	2,715	1,061	195	4	1,260
30	Moore	193	107	43	5	155
31	Musselshell	60	62	28	-	90
32	Nashua	290	196	67	3	266
33	Neihart	51	196	37	2	235
34	Nevada City	-	-	8	-	8
35	Norris	-	56	43	2	101
36	Nye	-	61	7	1	69
37	Paradise	163	161	56	9	226
38	Park City	983	437	74	5	516
39	Philipsburg	820	1,781	341	26	2,148
40	Plains	1,048	1,620	454	25	2,099
41	Pony	118	133	26	4	163
42	Power	179	87	47	2	136
43	Pray	681	25	2	1	28
44	Radersburg	66	81	25	1	107
45	Ramsay	-	56	29	1	86
46	Raynesford	-	68	36	3	107
47	Red Lodge	2,125	1,963	404	24	2,391
48	Reedpoint	193	163	55	3	221
49	Ringling	-	43	30	3	76
50	Rocker	-	54	21	2	77

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Rockvale	-	2	-	-	2
2	Roscoe	15	87	11	-	98
3	Roundup	1,788	1,097	405	20	1,522
4	Rudyard	258	156	63	2	221
5	Ryegate	245	146	70	11	227
6	Saco	197	158	96	5	259
7	Saint Marie	264	301	46	3	350
8	Saint Regis	319	485	172	14	671
9	Saltese	-	40	21	1	62
10	Sand Coulee	212	154	49	4	207
11	Sapphire Village	-	64	6	-	70
12	Shawmut	42	54	33	3	90
13	Sheridan	642	902	250	42	1,194
14	Silesia	96	41	9	1	51
15	Silverbow	-	12	4	1	17
16	Springdale	42	39	13	7	59
17	Square Butte	-	38	25	2	65
18	Stanford	401	335	202	7	544
19	Stevensville	1,809	2,008	564	73	2,645
20	Stockett	169	158	58	3	219
21	Sumatra	-	-	3	-	3
22	Superior	812	898	274	26	1,198
23	Taft	-	-	2	-	2
24	Tampico	-	12	6	-	18
25	Thompson Falls	1,313	1,092	352	31	1,475
26	Three Forks	1,869	1,373	487	72	1,932
27	Toston	108	49	40	23	112
28	Townsend	1,878	1,262	342	23	1,627
29	Tracy	-	93	12	4	109
30	Turah	306	15	1	-	16
31	Twin Bridges	375	313	152	23	488
32	Twodot	-	51	48	5	104
33	Ulm	738	428	120	10	558
34	Utica	-	2	5	1	8
35	Valier	509	372	187	33	592
36	Vaughn	658	244	44	8	296
37	Victor	745	798	271	22	1,091
38	Virginia City	190	185	105	1	291
39	Wagner	-	48	22	1	71
40	Walkerville	675	255	30	3	288
41	Warm Springs	-	-	3	-	3
42	Washoe	-	7	2	-	9
43	West Yellowstone	1,271	2	11	-	13
44	White Sulphur Springs	939	805	376	55	1,236
45	Whitehall	1,038	1,001	277	56	1,334
46	Wickes	-	1	-	-	1
47	Williamsburg	-	1	1	-	2
48	Willow Creek	210	139	57	21	217
49	Windham	-	47	32	2	81
50	Winston	147	133	46	3	182

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Wolf Creek	-	411	163	10	584
2	Yellowstone Club	-	273	3	-	276
3	Zurich	-	108	79	12	199
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49	<b>Total</b>	502,689	283,145	63,728	5,527	352,400

1/ Customer populations represent an average of the 12 month period from 01/01/14 through 12/31/14. YNP customer counts have been excluded.



Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1	Utility Operations			
2				
3		2	2	2
4		108	155	132
5		128	138	133
6		29	28	29
7		528	517	523
8		279	273	276
9		40	121	81
10		19	20	20
11				
12				
13				
14				
15				
16				
17				
18	TOTAL EMPLOYEES	1,133	1,254	1,194
	1/ Consistent with prior years, part time employees have been converted to full-time equivalents.			

Sch. 31	MONTANA CONSTRUCTION BUDGET 2015 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	<b>Electric Operations</b>		
3	MT Elec Trans - Columbus-Rapelje to Chrome Jct 100kv line	\$12,207,093	\$12,207,093
4	MT Elec Trans - Jack-Rabbit-Big Sky 161kv Line	11,199,193	11,199,193
5	MT Elec Trans - NERC Facilities Compliance 230/161 and 115/100	11,000,000	11,000,000
6	MT Elec Trans - 500kv Broadview bank 4 sub replacement	1,300,000	1,300,000
7	MT Elec Trans - 500KV Colstrip spare autobank	1,961,693	1,961,693
8	MT Elec Trans - Crooked Falls Switchyard Expansion	2,900,000	2,900,000
9	MT Elec Trans - Dillon-Salmon 161-69 Auto Bank upgrade	2,600,000	2,600,000
10	MT Elec Trans - Judith Gap ring bus	2,093,200	2,093,200
11	MT Elec Distribution - YNP Communication Infrastructure	1,178,139	1,178,139
12	MT Elec Distribution - Elec Distribution Infrastructure Plan	46,331,076	46,331,076
13	MT Elec Distribution - Billings 8th Street ring bus	2,142,222	2,142,222
14	MT Elec Subs - Millcreek reactors	1,300,000	1,300,000
15	MT Elec Trans - Anaconda-Deer Lodge 100kv pole replace	1,591,692	1,591,692
16	MT Elec Trans - Missoula-Drummond 100kv pole replace	1,116,000	1,116,000
17	MT Elec Transmission - Red Lodge-Bridget B line capacity	1,466,447	1,466,447
18	SD Elec Trans - Yankton East 115KV Trans Source and sub	11,660,681	-
19			
20	All Other Projects < \$1 Million Each	64,825,270	48,396,929
21			
22	<b>Total Electric Utility Construction Budget</b>	<b>176,872,706</b>	<b>148,783,684</b>
23			
24	<b>Natural Gas Operations</b>		
25	MT Gas Retail - Gas Distribution Infrastructure Plan	4,875,000	4,875,000
26	MT Gas Retail - Service replacements with meter move outs	1,458,946	1,458,946
27	MT Gas Trans - GTIP Butte-Bozeman line reroute	1,628,201	1,628,201
28	MT Gas Trans - GTIP Missoula Rattlesnake Stone Container	2,967,286	2,967,286
29	MT Gas Trans - Station W horsepower	2,211,432	2,211,432
30			
31	All Other Projects < \$1 Million Each	19,016,019	14,352,126
32			
33	<b>Total Natural Gas Utility Construction Budget</b>	<b>32,156,884</b>	<b>27,492,991</b>
34			
35	<b>Common</b>		
36	Fleet and Equipment Purchases	6,260,000	4,332,000
37	MT Facilities new Butte G.O. Building	18,205,663	18,205,663
38	MT Communications fiber backbone	1,900,852	1,900,852
39	MT Communications south Butte concentrator fiber	1,253,525	1,253,525
40	MT Communications AASTRA TSE upgrade	1,132,018	1,132,018
41	MT Ovando-Hot Springs CSKT 230kv permit renewal	3,828,000	3,828,000
42	MT Bozeman building upgrade	999,962	999,962
43			
44	All Other Projects < \$1 Million Each	10,850,715	7,642,208
45	(Includes IT, Communications, Facilities, Cust Serv)		
46			
47			
48	<b>Total Common Utility Construction Budget</b>	<b>44,430,735</b>	<b>39,294,228</b>
49			
50	MT CU4 capital additions - PPL invoice	4,076,850	4,076,850
51	MT - Hydro Generation upgrades	9,523,000	9,523,000
52	SD Big Stone, Neal 4, Coyote partner capital	5,357,074	-
53	SD Generation - Big Stone and Neal environmental upgrades	32,943,122	-
54			
55	All Other Projects < \$1 Million Each	1,071,653	1,071,653
56			
57	<b>Total MT/SD Generation</b>	<b>52,971,699</b>	<b>14,671,503</b>
58	<b>TOTAL CONSTRUCTION BUDGET</b>	<b>\$306,432,024</b>	<b>\$230,242,406</b>

Sch. 32	TOTAL SYSTEM & MONTANA PEAK AND ENERGY					
		System Peak and Energy				
		Peak Day	Peak Hour	Peak Day Volume Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	January	5	19:00	2,090	787,363	173,528
2	February	6	8:00	2,233	762,133	160,982
3	March	1	20:00	2,151	691,247	167,529
4	April	2	8:00	1,810	715,252	186,850
5	May	28	18:00	1,867	631,592	181,070
6	June	24	17:00	1,828	598,391	197,732
7	July	30	17:00	2,282	751,033	164,877
8	August	11	17:00	2,293	881,557	258,370
9	September	25	17:00	2,007	779,094	241,851
10	October	28	8:00	1,858	670,869	189,857
11	November	13	19:00	2,215	822,684	184,273
12	December	30	19:00	2,305	989,842	225,737
13	TOTALS				9,081,057	2,332,656
14		Montana Peak and Energy				
15		Peak Day	Peak Hour	Peak Day Volume Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
16						
17	January					
18	February					
19	March					
20	April					
21	May					
22	June					
23	July					
24	August					
25	September					
26	October					
27	November					
28	December					
29	TOTALS				-	-

Sch. 33	MONTANA SYSTEM SOURCES & DISPOSITION OF ENERGY			
	Sources	Megawatthours	Dispositions	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,419,412		
3	Nuclear	-	<b>Sales to Ultimate Consumers</b>	6,001,904
4	Hydro - Conventional	458,400	(Include Interdepartmental) 1/	
5	Hydro - Pumped Storage	-		
6	Other	547,125	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	
8	<b>Net Generation</b>	2,424,937	Non-Requirement Sales	2,332,656
9	<b>Purchases</b>	6,652,978	<b>Sales for Resale</b>	2,332,656
10	Power Exchanges			
11	Received	201,799		
12	Delivered	198,657	Energy Furnished w/o Charge	-
13	<b>Net Power Exchanges</b>	3,142	<b>Energy Furnished</b>	-
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	11,323,140	Electric Department	
16	Delivered	11,323,140	(Less) Station Use	-
17	<b>Net Transmission Wheeling</b>	-	<b>Net Energy Used Within Util.</b>	-
18	<b>Transmission by Others Losses</b>	-	<b>Energy Losses</b>	746,497
19	<b>TOTAL SOURCES</b>	9,081,057	<b>TOTAL DISPOSITIONS</b>	9,081,057

1/ The megawatts hours listed above do not include sales to billed choice customers, consistent with the presentation used in the corresponding schedule on FERC Form 1. It also includes unbilled consumption of (4,002) megawatt hours.

Sch. 34	SOURCES OF MONTANA ELECTRIC SUPPLY				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Steam Generation	Colstrip Unit 4	Colstrip, MT	222.0	1,419,412
2	Gas Turbine Generation	Dave Gates Station	Anaconda, MT	150.0	410,974
3	Wind Generation	Spion Kop	Judith Basin County, MT	40.0	136,151
4	Hydro Generation	Black Eagle	Great Falls, MT	21.0	14,384
5	Hydro Generation	Cochrane	Great Falls, MT	64.0	31,117
6	Hydro Generation	Hauser	Helena, MT	19.0	16,982
7	Hydro Generation	Holter	Helena, MT	48.0	35,934
8	Hydro Generation	Kerr	Polson, MT	194.0	143,763
9	Hydro Generation	Madison	Ennis, MT	8.0	7,837
10	Hydro Generation	Morony	Great Falls, MT	48.0	35,673
11	Hydro Generation	Mystic	Columbus, MT	12.0	6,979
12	Hydro Generation	Rainbow	Great Falls, MT	64.0	45,566
13	Hydro Generation	Ryan	Great Falls, MT	60.0	58,232
14	Hydro Generation	Thompson Falls	Thompson Falls, MT	94.0	61,933
15	Total Generation			1,044.0	2,424,937
16	Purchases	Small Power Producers	Colstrip Energy, Ltd.	3.3	308,755
17	Purchases	Small Power Producers	Billings Generation, Inc.	5.1	404,693
18	Purchases	Small Power Producers	State of Montana - DNRC	0.8	52,101
19	Purchases	Small Power Producers	Gordon Butte Wind	0.8	39,434
20	Purchases	Small Power Producers	Musselshell Wind 1	0.9	26,446
21	Purchases	Small Power Producers	Musselshell Wind 2	0.8	31,139
22	Purchases	Small Power Producers	Others	2.7	71,777
23	Subtotal			14.4	934,345
24	Purchased Power		Avista Utility	0.0	202,716
25	Purchased Power		Barclays Bank	0.0	244,800
26	Purchased Power		Basin Power Plant	0.0	52,594
27	Purchased Power		Black Hills Power	0.0	3,530
28	Purchased Power		BPA	0.0	42,193
29	Purchased Power		Capital Power	0.0	675
30	Purchased Power		Cargill Power Markets	0.0	446,778
31	Purchased Power		Citigroup Energy	0.0	315,568
32	Purchased Power		Coral/Shell Energy	0.0	105,231
33	Purchased Power		Constellation Power Marketing	0.0	10,060
34	Purchased Power		Credit Suisse	0.0	16,816
35	Purchased Power		Deutsche Bank	0.0	122,400
36	Purchased Power		Eugene Water and Power	0.0	290
37	Purchased Power		Iberdrola Renewables	0.0	66,705
38	Purchased Power		Idaho Power Company	0.0	38,845
39	Purchased Power		Judith Gap	0.0	509,782
40	Purchased Power		Macquarie Cook Energy	0.0	3,897
41	Purchased Power		Merrill Lynch Commodities	0.0	96,600
42	Purchased Power		Morgan Stanley	0.0	630,128
43	Purchased Power		PacifiCorp	0.0	12,035
44	Purchased Power		Portland General Electric	0.0	80,465
45	Purchased Power		Powerex	0.0	363,209
46	Purchased Power		PPL Montana	0.0	1,771,687
47	Purchased Power		Puget Sound Energy	0.0	73,064
48	Purchased Power		Rainbow Energy	0.0	160,318
49	Purchased Power		Seattle City Light	0.0	53,550
50	Purchased Power		Southern California Edison	0.0	16,739
51	Purchased Power		Tacoma Power	0.0	10,624
52	Purchased Power		Tenaska	0.0	1,245
53	Purchased Power		The Energy Authority	0.0	24,557
54	Purchased Power		Tiber Dam	0.0	26,860
55	Purchased Power		Transalta Energy Marketing	0.0	133,667
56	Purchased Power		Turnbull Hydro	0.0	28,354
57	Purchased Power		United Materials of Great Falls	0.0	7
58	Purchased Power		WAPA	0.0	25
57	Subtotal			0.0	5,666,014
58	System Balancing Transactions		Coral/Shell Energy	0.0	49,445
59	Reserve Sharing				3,174
60	Total Purchases				6,652,978

Sch. 34A		THERMAL GENERATION OUTAGE REPORT		
	Unit	Outage Start Date	Description	Outage Duration (hours)
1	Colstrip Unit 3	2/3/2014	Boiler reheat tube leak	73
2				
3		3/22/2014	Boiler tube leak	63
4				
5		7/4/2014	Overhaul	1,249
6				
7		5/9/2014	Boiler ash issues	18
8				
9		8/23/2014	Circulating water pump trip	22
10				
11	Colstrip Unit 4	11/6/2014	Boiler tube leaks	71
12				
13		12/12/2014	Generator hydrogen seal replacement	213
14				
15		12/26/2014	Boiler water circulating pump - purge line leak	31
16				
17				
18		1/1/2014	Generator ground fault relay energized	503
19				
20		1/22/2014	Repair gross MW reporting mechanism	21
21				
22		4/23/2014	Boiler tube leak	110
23				
24				
25				
26				
27				
Only outages greater than 12 hours are reported.				
We own 30% of Colstrip Unit 4 and have a reciprocal sharing agreement with the 30% owner of Colstrip Unit 3 in which we share equally in the ownership benefits and liabilities of each.				

Sch. 34B		THERMAL GENERATION OUTAGE REPORT		
	Unit	Outage Start Date	Description	Outage Duration (hours)
1	DGGS Unit 1	7/24/2014	Annual maintenance outage	66
2				
3		8/3/2014	Exhaust case erosion	85
4				
5		9/25/2014	Lube oil filters plugged	38
6				
7		9/26/2014	Bearing failure	70
8				
9		10/3/2014	Bearing failure	12
10				
11		10/27/2014	Replaced leased power turbine with repaired turbine	80
12				
13		12/27/2014	Bearing failure	48
14				
15				
16	DGGS Unit 2	1/1/2014	Power turbine change out	273
17				
18		5/3/2014	Multiple signal failures	98
19				
20		7/15/2014	Bearing failure	28
21				
22		7/16/2014	Bearing failure	836
23				
24		7/22/2014	Annual maintenance outage	30
25				
26		8/12/2014	Step up transformer maintenance	31
27				
28		9/24/2014	Power turbine inspection	48
29				
30		9/29/2014	Remove engine to ship offsite for repairs	2,245
31				
32				
33	DGGS Unit 3	6/29/2014	HVAC fire triggered fire suppression system	40
34				
35		7/27/2014	Annual maintenance outage	153
36				
37		9/19/2014	Bearing failure	29
38				
39		9/20/2014	Bearing failure	64
40				
41		9/26/2014	Install blanking plate	51
42				
43		10/10/2014	High K-flange vibrations and high gear box pressures	118
44				
45		10/20/2014	Combustion turbine removal due to high K-flange vibration	131
46				
47		11/12/2014	Remove leased combustion turbine and install rebuilt one	81
48				
49		12/17/2014	Bearing seal worn or damaged	164
50				
51				
52				
53				
54				
Only outages greater than 12 hours are reported.				

Sch. 34C		HYDRO GENERATION OUTAGE REPORT		
	Unit	Outage Start Date	Description	Outage Duration (hours)
1	Black Eagle	11/18/2014	Convert turbine bearing from oil to marine	1,056
2				
3				
4				
5				
6	Cochrane	11/18/2014	Dredge intake area	181
7				
8		12/10/2014	Broken pipe at draft tube entrance	20
9				
10				
11				
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44				
45				
46				
Only outages greater than 12 hours since we took ownership of the hydro facilities on 11/18/14 are reported.				
Schedule 34C				



Sch. 35	MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS						
	Program Description (These are Electric DSM Programs)	Current Year Expenditures	Previous Year Expenditures	% Change	Planned Savings (MWH)	Achieved Savings (MWH)	Difference (MWH)
1							
2	2014 Residential Lighting Program	\$ 1,286,704	\$ 1,846,591	-30.32%	20,903	22,750	1,847
3							
4	2014 Commercial Lighting Program	\$ 2,004,501	\$ 3,710,079	-45.97%	10,264	11,171	907
5							
6	2014 E+ Business Partners Program (Electric)	\$ 1,616,456	\$ 1,081,852	49.42%	3,615	3,934	319
7							
8	2014 E+ Residential Electric New Construction Program	\$ 4,511	\$ 12,463	-63.81%	7	7	1
9							
10	2014 E+ Residential Electric Savings Program	\$ 16,456	\$ 55,299	-70.24%	23	25	2
11							
12	2014 Northwest Energy Efficiency Alliance (NEEA)*	\$ 1,088,651	\$ 1,812,164	-39.93%	11,862	12,910	1,048
13							
14	2014 E+ Commercial Electric New Construction Program	\$ 76,424	\$ 80,493	-5.06%	517	562	46
15							
16	2014 E+ Commercial Electric Savings Program	\$ 490,113	\$ 763,461	-35.80%	1,159	1,261	102
17							
18							
19							
20							
21							
22	A program participant is a Montana residential and/or commercial electric customer who installs eligible energy conservation measures and receives financial incentives/rebates either directly or indirectly.						
23							
24							
25							
26							
27	*Note: 2014 NEEA expenditures are allocated to electric DSM but there are gas savings as a result of some NEEA Programs.						
28							
29							
30							
31							
32							
33							
34	TOTAL	\$ 6,583,815	\$ 9,362,402	-29.68%	48,347	52,620	4,272

Sch. 35a	Electric Universal System Benefits Programs						
	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings		Most recent program evaluation
					MWh	MW	
1	Local Conservation						
2	E+ Residential Audit/Sm. Comm Audit	\$ 606,705	\$ 500,000	\$ 1,106,705	616	0.137	2012
3	E+ Business Partners / Irrigation Projects	273,050	-	273,050	1,083	0.198	2012
4	NWE Promotion	75,799	-	75,799			
5	NWE Labor	33,191	-	33,191			
6	NWE Admin. Non-labor	29,602	-	29,602			
7	USB Interest & Svc Chg	(304)	-	(304)			
8	Market Transformation						
9	E+ Commercial Lighting	603	-	603	11	0.004	2012
10	Motor Management Training	-	-	-			
11	Energy Star Homes	74,182	-	74,182	31		2012
12	Building Operator Certification	-	-	-			
13	Commercial Industrial Training & Conference	37,660	-	37,660			
14	NWE Promotion	16,288	-	16,288			
15	NWE Labor	19,678	-	19,678			
16	NWE Admin. Non-labor	28,237	-	28,237			
17	USB Interest & Svc Chg	(194)	-	(194)			
18	Renewable Resources						
19	Generation/Education	13,788	938,903	952,691	11	0.008	2012
20	Green Power Product Offering	566	-	566			
21	NWE Promotion	7,632	-	7,632			
22	NWE Labor	52,197	-	52,197			
23	NWE Admin. Non-labor	2,416	-	2,416			
24	USB Interest & Svc Chg	(347)	-	(347)			
25	Research & Development						
26	R&D/ Infrastructure	72,282	271,868	344,150			
27	Battery Storage	3,705	-	3,705			
28	Energy Corps	12,330	40,000	52,330			
29	NWE Promotion	3,773	-	3,773			
30	NWE Labor	8,563	-	8,563			
31	NWE Admin. Non-labor	225	-	225			
32	USB Interest & Svc Chg	(80)	-	(80)			
33	Low Income						
34	Bill Assistance	2,421,608	-	2,421,608			
35	Free Weatherization	408,725	307,977	716,702	132	0.069	2012
36	Elec Wx Incentives	16,916	-	16,916			
37	Fuel Switch Analyses	2,400	-	2,400			
38	Energy Share	239,000	85,158	324,158			
39	NWE Promotion	13,512	-	13,512			
40	NWE Labor	35,324	-	35,324			
41	NWE Admin. Non-labor	1,693	-	1,693			
42	USB Interest & Svc Chg	(877)	-	(877)			
43	Returned Low Income Funds from DPHHS <sup>(a)</sup>	(1,257)	-	(1,257)			
44	Large Customer Self Directed						
45	Self-Directed Energy Reduction	2,063,099	698,870	2,761,969			
46	Self-Directed to Low Income	123,538	-	123,538			
47	NWE Labor	12,621	-	12,621			
48	USB Interest & Svc Chg	(783)	-	(783)			
49	NWE Allocated from 2013 to cover LC Expense <sup>(b)</sup>	(6,839)	-	(6,839)			
50	Total	\$ 6,700,225	\$ 2,842,776	\$ 9,543,001	1,884	0.416	
51	Number of customers that received low income rate discounts				12,569		
52	Average monthly bill discount amount (\$/mo)				\$ 16.06		
53	Average LIEAP-eligible household income				n/a		
54	Number of customers that received weatherization assistance				300 <sup>(c)</sup>		
55	Expected average annual bill savings from weatherization				441 Kwh		
56	Number of residential audits performed on-site				1,840 <sup>(c)</sup>		
57	Number of residential audits performed off-site				975 <sup>(c)</sup>		
58	<sup>(a)</sup> As a result of DPHHS weatherization monitoring findings of \$17.62 from the 2012 contract and \$1239.77 from the 2013 contract \$1257.39 has been returned to NorthWestern.						
59	<sup>(b)</sup> The 2014 Large Customer Admin Costs of \$12,621 less the interest income of \$783 exceeded the amount of unclaimed 2014 Large Customer funds of \$4,999. Northwestern has committed unclaimed 2013 Large Customer funds in the amount of \$6,839 to cover the deficit.						
60	<sup>(c)</sup> Total savings and number of customers is reported for the combination of 2014 electric and natural gas USB funds expended in 2014.						

Sch. 35b	Montana Conservation & Demand Side Management Programs					
	Program Description (These are electric USB Programs)	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	<b>Local Conservation</b>					
2	E+ Energy Audit for the Home or Business	\$ 977,760	\$ -	\$ 977,760	0.22 993	2012
3						
4	E+ Business Partners Program (Electric)	\$ -	\$ -	\$ -	-	2012
5						
6	<b>Commercial Lighting</b>					
7	E+ Commercial Lighting Program	\$ 603	\$ -	\$ 603	0.004 11	2012
8						
9	<b>Market Transformation</b>					
10	Motor Management Training	\$ 13,299	\$ -	\$ 13,299	-	2012
11						
12	Building Operator Certification	\$ 23,194	\$ -	\$ 23,194	-	2012
13					1,267	
14	Regional Market Transformation	\$ 37,660			-	2012
15						
16	<b>Renewables and Research &amp; Development</b>					
17	Generation/Education	\$ 770,473	\$ -	\$ 770,473	0.50 651	2012
18						
19	Green Power Product	\$ 566	\$ -	\$ 566	-	2012
20						
21	R&D / Infrastructure	\$ 369,831	\$ -	\$ 369,831	-	2012
22						
23	<b>Low Income</b>					
24	Free Weatherization	\$ 858,757	\$ -	\$ 858,757	-	2012
25					165	
26	Fuel Switch	\$ 2,400	\$ -	\$ 2,400	0.14	2012
27					107	
28	<b>Other</b>					
29	E+ Irrigator Program	\$ 273,050	\$ -	\$ 273,050	0.40 1,358	2012
30						
31	E+ New Homes Program	\$ 74,182	\$ -	\$ 74,182	-	2012
32					31	
33	Total	\$ 3,401,775	\$ -	\$ 3,401,775	1.26	
34					4,584.93	

Sch. 36	MONTANA CONSUMPTION AND REVENUES - ELECTRIC (EXCLUDES YNP)						
		Operating Revenues 1/		MWH Sold		Average Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	<b>Sales of Electricity</b>						
2							
3	Residential	\$257,285,796	\$269,817,879	2,398,535	2,409,737	283,145	276,174
4	Commercial & Industrial	368,828,640	368,019,550	6,115,143	6,180,108	65,138	64,023
5	Public Street & Highway Lighting	15,647,698	15,688,002	60,206	60,599	3,827	3,767
6	Sales to Other Utilities	63,924,368	45,871,121	2,332,656	1,871,374	18	18
7	Interdepartmental	1,125,772	1,133,609	10,955	11,128	290	290
8							
9	<b>TOTAL SALES</b>	<b>\$706,812,274</b>	<b>\$700,530,161</b>	<b>10,917,495</b>	<b>10,532,946</b>	<b>352,418</b>	<b>344,272</b>
10							
11	1/ Revenue and MWHs include unbilled.						
12							
13							
14							
15							
16							