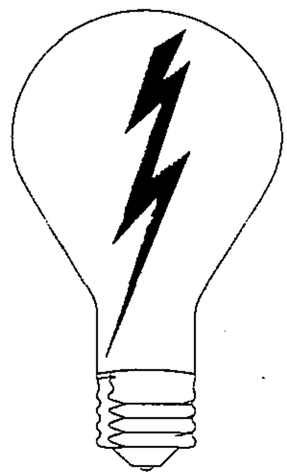
YEAR ENDING 2015

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

Table of Contents

continued on next page

Sch. 1	IDENTIFICATION
Legal Name of Respondent:	NorthWestern Corporation
Name Under Which Respondent Does Business:	NorthWestern Energy
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	Crystal D. Lail
Telephone Number for Report Inquiries:	(406) 497-2759
Address for Correspondence Concerning Report:	40 East Broadway Street Butte, MT 59701

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

N/A

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

Reflects active officers as of December 31, 2015.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		$ 148,050	97.91%
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including CMP, HPC, Lodge Creek Pipelines, LLC and Willow Creek Gathering, LLC) Propane Utility		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		$ 3,159	2.09%
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
Risk Partners Assurance, Ltd.	Captive insurance company		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Total Corporation		$ 151,209	100.00%

Sch. 5	CORPORATE ALLOCATIONS				
Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Controller	Includes the following departments: Controller, Accounting Accounts Payable, Payroll, Financial Reporting and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$17,052,979	73.74%	$6,072,235
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.	22,854,249	74.85%	7,680,893
Legal Department	Includes the following departments: Chief Legal, Record Services, Compliance, Risk Mgmt	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	10,597,679	79.48%	2,736,067
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.	17,337,416	78.74%	4,681,782
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research, Government Affairs, Reg Support Services, Community Relations & Public Affairs.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	3,959,020	89.77%	451,353
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.	2,994,378	76.39%	925,550
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.	915,201	78.00%	258,134
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.	511,761	78.00%	144,343
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.	3,579,623	100.00%	0
TOTAL			$79,802,306	77.66%	$22,950,357

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	**Total Nonutility Subsidiaries**			$0		$0
5	**Total Nonutility Subsidiaries Revenues**			$0		
6						
7						
8						
9	**Utility Subsidiaries**					
10						
11	**Total Utility Subsidiaries**			$0		$0
12	Canadian-Montana Pipeline Corporation	Natural gas pipeline	Contract rate	$170,463		
13	Havre Pipeline Company, LLC	Natural gas gathering	Tariffed rate	4,470,008		
14	**Total Utility Subsidiaries Revenues**			$4,640,471		
15	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6	**Total Nonutility Subsidiaries**			$0		$0
7	**Total Nonutility Subsidiaries Expenses**			$0		
8						
9						
10						
11	**Utility Subsidiaries**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	$500,400	13.1%	$500,400
14						
15	**Total Utility Subsidiaries**			$500,400		$500,400
16	**Total Utility Subsidiaries Expenses**			$3,847,776		
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						
2	400 Operating Revenues	$ 978,879,709	$ 154,155,178	$ 824,724,531	$ 780,678,190	5.64%
3						
4	**Total Operating Revenues**	978,879,709	154,155,178	824,724,531	780,678,190	5.64%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	504,689,141	101,313,292	403,375,849	462,844,641	-12.85%
9	402 Maintenance Expense	51,944,748	10,565,889	41,378,859	42,418,160	-2.45%
10	403 Depreciation Expense	110,791,419	19,795,679	90,995,740	79,193,854	14.90%
11	404-405 Amort. of Electric Plant	4,567,061	786,705	3,780,356	3,017,852	25.27%
12	406 Amort. of Plant Acquisition Adj.	5,436,413	(1,565,999)	7,002,412	937,002	>300.00%
13	407.3 Regulatory Amortizations - Debit	(3,330,150)	961,779	(4,291,929)	1,625,341	>-300.00%
14	407.4 Regulatory Amortizations - Credit	(11,454,417)	-	(11,454,417)	(15,521,641)	26.20%
15	408.1 Taxes Other Than Income Taxes	110,420,466	5,336,527	105,083,939	84,188,473	24.82%
16	409.1 Income Taxes - Federal	(2,841,271)	(7,587,131)	4,745,860	6,363,318	-25.42%
17	- Other	485,752	(1,286,157)	1,771,909	1,926,133	-8.01%
18	410.1 Deferred Income Taxes-Dr.	251,776,845	11,738,431	240,038,414	152,082,336	57.83%
19	411.1 Deferred Income Taxes-Cr.	(233,071,598)	(9,696,520)	(223,375,078)	(160,837,580)	-38.88%
20	411.4 Investment Tax Credit Adj.	(206,132)	(206,132)	-	-	-
21	411.6 Gain from Disposition of Property	-	-	-	-	-
22	411.7 Loss from Disposition of Property	-	-	-	-	-
23	411.8 SO2 Allowances	(12)	(10)	(2)	(7)	71.55%
24						
25	**Total Operating Expenses**	789,208,265	130,156,353	659,051,912	658,237,882	0.12%
26	**NET OPERATING INCOME**	$ 189,671,444	$ 23,998,825	$ 165,672,619	$ 122,440,308	35.31%

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.

Sch. 9	MONTANA REVENUES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	440 Residential	$ 330,456,405	$ 52,015,532	$ 278,440,873	$ 257,285,796	8.22%
5	442 Commercial	427,498,217	83,259,390	344,238,827	318,009,360	8.25%
6	Industrial	55,421,112	-	55,421,112	50,819,280	9.06%
7	444 Public Street, Highway Lighting					
8	& Other Sales to Public Authorities	18,245,986	2,190,412	16,055,574	15,647,698	2.61%
9	448 Interdepartmental Sales	1,194,030	-	1,194,030	1,125,772	6.06%
10						
11	**Total Sales to Ultimate Consumers**	832,815,750	137,465,334	695,350,416	642,887,906	8.16%
12	447 Sales for Resale	84,836,564	20,526,494	64,310,070	63,924,368	0.60%
13						
14	**Total Sales of Electricity**	917,652,314	157,991,828	759,660,486	706,812,274	7.48%
15	449.1 Provision for Rate Refunds	(13,004,929)	(6,273,362)	(6,731,567)	1,072,047	>-300.00%
16						
17	**Total Revenue Net of Rate Refunds**	904,647,385	151,718,466	752,928,919	707,884,321	6.36%
18						
19	**Other Operating Revenues**					
20	450 Forfeited Discounts & Late Pymt Rev	496,283	496,283	-	-	-
21	451 Miscellaneous Service Revenue	188,557	188,557	-	-	-
22	453 Sales of Water & Water Power	3,608,140	-	3,608,140	570,825	>300.00%
23	454 Rent From Electric Property	2,881,173	244,988	2,636,185	2,663,466	-1.02%
24	456 Other Electric Revenues	67,058,171	1,506,884	65,551,287	69,559,578	-5.76%
25						
26	**Total Other Operating Revenue**	74,232,324	2,436,712	71,795,612	72,793,869	-1.37%
27	**TOTAL OPERATING REVENUE**	$ 978,879,709	$ 154,155,178	$ 824,724,531	$ 780,678,190	5.64%

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	**Power Production Expenses**					
2						
3	**Steam Power Generation-Operation**					
4	500 Supervision & Engineering	$ 1,201,051	$ 1,150,152	$ 50,899	$ 40,057	27.07%
5	501 Fuel	47,776,867	21,283,454	26,493,413	25,489,629	3.94%
6	502 Steam Expenses	2,678,123	1,121,348	1,556,775	1,503,789	3.52%
7	503 Steam from Other Sources	-	-	-	-	-
8	505 Electric Plant	729,508	468,161	261,347	291,361	-10.30%
9	506 Miscellaneous Steam Power	2,970,688	1,375,219	1,595,469	1,507,451	5.84%
10	507 Rents	61,559	28,795	32,764	36,407	-10.01%
11	**Total Operation-Steam Power Gen.**	55,417,796	25,427,129	29,990,667	28,868,694	3.89%
12	**Steam Power Generation-Maintenance**					
13	510 Supervision & Engineering	800,212	408,702	391,510	410,391	-4.60%
14	511 Structures	1,073,279	406,847	666,432	678,677	-1.80%
15	512 Steam Boiler Plant	5,830,556	2,656,686	3,173,870	4,312,900	-26.41%
16	513 Electric Plant	1,734,718	1,386,474	348,244	1,445,552	-75.91%
17	514 Miscellaneous Steam Plant	870,388	437,914	432,474	602,259	-28.19%
18	**Total Maintenance-Steam Power Gen.**	10,309,153	5,296,623	5,012,530	7,449,779	-32.72%
19	**Total Steam Power Generation**	65,726,949	30,723,752	35,003,197	36,318,473	-3.62%
20	**Hydro Power Generation-Operation**					
21	535 Supervision & Engineering	946,345	-	946,345	131,681	>300.00%
22	536 Water for Power	964,488	-	964,488	117,070	>300.00%
23	537 Hydraulic Expenses	3,777,397	-	3,777,397	427,823	>300.00%
24	538 Electric Expenses	4,120,628	-	4,120,628	485,031	>300.00%
25	539 Miscellaneous Hydraulic Power	2,095,260	-	2,095,260	134,946	>300.00%
26	540 Rents	15,336,201	-	15,336,201	2,912,990	>300.00%
27	**Total Operation-Hydro Power Gen.**	27,240,319	-	27,240,319	4,209,541	>300.00%
28	**Hydro Power Generation-Maintenance**					
29	541 Supervision & Engineering	881,188	-	881,188	116,667	>300.00%
30	542 Structures	476,174	-	476,174	18,293	>300.00%
31	543 Reservoirs, Dams & Waterways	727,869	-	727,869	152,003	>300.00%
32	544 Electric Plant	1,562,249	-	1,562,249	240,427	>300.00%
33	545 Miscellaneous Hydro Plant	1,706,212	-	1,706,212	-	-
34	**Total Maintenance-Hydro Power Gen.**	5,353,692	-	5,353,692	527,390	>300.00%
35	**Total Hydraulic Power Generation**	32,594,011	-	32,594,011	4,736,931	>300.00%
36	**Other Power Generation-Operation**					
37	546 Supervision & Engineering	1,124,090	227,151	896,939	1,063,417	-15.66%
38	547 Fuel	14,630,970	525,366	14,105,605	22,752,645	-38.00%
39	548 Generation Expenses	3,995,439	1,272,084	2,723,355	2,609,558	4.36%
40	549 Miscellaneous Other Power	965,980	201,389	764,591	2,783,461	-72.53%
41	550 Rents	-	-	-	-	-
42	**Total Operation-Other Power Gen.**	20,716,479	2,225,990	18,490,490	29,209,081	-36.70%
43	**Other Power Generation-Maintenance**					
44	551 Supervision & Engineering	116,945	116,945	-	-	-
45	552 Structures	20,777	-	20,777	1,290	>300.00%
46	553 Generating & Electric Plant	1,807,998	487,063	1,320,935	3,673,793	-64.04%
47	554 Miscellaneous Other Power Plant	109,967	3,972	105,995	133,988	-20.89%
48	**Total Maintenance-Other Power Gen.**	2,055,687	607,980	1,447,707	3,809,071	-61.99%
49	**Total Other Power Generation**	22,772,166	2,833,970	19,938,197	33,018,152	-39.61%
50	**Other Power Supply Expenses**					
51	555 Purchased Power	244,320,023	50,797,378	193,522,645	294,847,064	-34.37%
52	556 System Control & Load Dispatch	136,976	136,976	-	-	-
53	557 Other Expenses	17,709,429	1,995,674	15,713,755	497,814	>300.00%
54	**Total Other Power Supply Expenses**	262,166,428	52,930,028	209,236,400	295,344,878	-29.16%
55	**Total Power Production Expenses**	383,259,554	86,487,750	296,771,805	369,418,435	-19.67%

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	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	3,974,649	408,414	3,566,235	3,402,695	4.81%
6	561 Load Dispatching	77,923	77,923	-	-	-
7	561.1 Load Dispatch - Reliability	949,842	-	949,842	887,900	6.98%
8	561.2 Load Disp-Monitor/Op	771,586	104,207	667,379	603,836	10.52%
9	561.3 Load Disp-Srv/Schedu	1,660,724	369,083	1,291,641	1,122,482	15.07%
10	561.4 Relia Pln/StdDev-RTO	-	-	-	-	-
11	561.5 Reliab. Plan, Stds	102,632	102,632	-	-	-
12	561.6 Transmission Service Studies	-	-	-	-	-
13	561.8 Sch,Sys&Ctrl Srv-RTO	6,000	6,000	-	-	-
14	562 Station Expenses	1,658,224	192,354	1,465,870	1,196,850	22.48%
15	563 Overhead Lines	1,340,570	339,503	1,001,067	910,518	9.94%
16	564 Underground Lines	-	-	-	-	-
17	565 Transmission of Elec. by Others	8,481,034	2,435,718	6,045,316	5,603,632	7.88%
18	566 Miscellaneous Transmission	528,187	545,604	(17,417)	14,069	-223.80%
19	567 Rents	769,153	5,130	764,023	927,940	-17.66%
20	**Total Operation-Transmission**	20,320,524	4,586,568	15,733,956	14,669,922	7.25%
21	**Transmission-Maintenance**					
22	568 Supervision & Engineering	1,529,340	242,215	1,287,125	1,372,546	-6.22%
23	569 Structures	35,186	1,458	33,728	16,065	109.94%
24	569.1 Maintenance of Computer Hardware	216,046	-	216,046	615,764	-64.91%
25	569.2 Maintenance of Computer Software	1,048,892	-	1,048,892	819,643	27.97%
26	569.3 Maint-Comm Equip	92,024	92,024	-	0	-100.00%
27	570 Station Equipment	1,390,352	129,109	1,261,243	964,256	30.80%
28	571 Overhead Lines	3,106,899	423,649	2,683,250	3,126,876	-14.19%
29	572 Underground Lines	175	176	(1)	-	-
30	573 Miscellaneous Transmission Plant	-	-	-	-	-
31	**Total Maintenance-Transmission**	7,418,914	888,631	6,530,283	6,915,150	-5.57%
32	**Total Transmission Expenses**	27,739,438	5,475,199	22,264,239	21,585,072	3.15%
33						
34	**Regional Market Operation**					
35	575.2 Day-Ahead & Real-time Admin	19,015	19,015	-		
36	575.5 Ancillary Services Mkt Admin	5,433	5,433	-		
37	575.6 Market Monitoring & Complaince	2,716	2,716	-		
38	**Total Operation-Regional Market**	27,164	27,164	-		
39						
40	**Distribution Expenses**					
41						
42	**Distribution-Operation**					
43	580 Supervision & Engineering	4,723,015	972,747	3,750,268	3,584,878	4.61%
44	581 Load Dispatching	-	-	-	-	-
45	582 Station Expenses	2,250,635	352,013	1,898,622	2,155,835	-11.93%
46	583 Overhead Lines	4,867,672	411,927	4,455,745	3,624,231	22.94%
47	584 Underground Lines	2,830,940	1,017,054	1,813,886	1,679,455	8.00%
48	585 Street Lighting & Signal Systems	880,004	42,839	837,165	872,644	-4.07%
49	586 Meters	3,452,849	667,966	2,784,883	2,935,794	-5.14%
50	587 Customer Installations	2,627,458	344,256	2,283,202	2,409,799	-5.25%
51	588 Miscellaneous Distribution	4,757,591	601,076	4,156,515	4,115,091	1.01%
52	589 Rents	73,660	-	73,660	58,341	26.26%
53	**Total Operation-Distribution**	26,463,824	4,409,878	22,053,946	21,436,068	2.88%
54	**Distribution-Maintenance**					
55	590 Supervision & Engineering	2,567,949	583,466	1,984,483	1,842,630	7.70%
56	591 Structures	40,127	-	40,127	31,175	28.71%
57	592 Station Equipment	1,156,687	310,284	846,403	1,042,116	-18.78%
58	593 Overhead Lines	15,160,031	2,080,600	13,079,431	13,552,193	-3.49%
59	594 Underground Lines	1,799,887	278,128	1,521,759	1,711,354	-11.08%
60	595 Line Transformers	160,384	13,929	146,455	166,340	-11.95%
61	596 Street Lighting, Signal Systems	1,104,495	157,967	946,528	1,005,585	-5.87%
62	597 Meters	1,453,059	71,719	1,381,340	1,425,318	-3.09%
63	598 Miscellaneous Distribution Plant	43,176	43,176	-	-	-
64	**Total Maintenance-Distribution**	23,485,795	3,539,269	19,946,526	20,776,712	-4.00%
65	**Total Distribution Expenses**	49,949,619	7,949,147	42,000,472	42,212,780	-0.50%

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	**Customer Accounts Expenses**					
3						
4	**Customer Accounts-Operation**					
5	901 Supervision	-	-	-	-	-
6	902 Meter Reading	2,406,892	799,731	1,607,161	1,718,304	-6.47%
7	903 Customer Records & Collection	7,741,867	1,339,369	6,402,498	6,275,544	2.02%
8	904 Uncollectible Accounts	1,420,070	134,348	1,285,722	2,166,728	-40.66%
9	905 Miscellaneous Customer Accts.	45,985	46,725	(740)	(375)	-97.21%
10	**Total Customer Accounts Expenses**	11,614,814	2,320,173	9,294,641	10,160,201	-8.52%
11						
12	**Customer Service & Information**					
13						
14	**Customer Service-Operation**					
15	907 Supervision	-	-	-	-	-
16	908 Customer Assistance	4,868,885	1,426,951	3,441,934	3,278,076	5.00%
17	909 Inform. & Instruct. Advertising	965,498	159,950	805,548	697,459	15.50%
18	910 Misc. Customer Service & Info.	858,992	-	858,992	829,161	3.60%
19	**Total Customer Service & Info. Expense**	6,693,375	1,586,901	5,106,474	4,804,696	6.28%
20						
21	**Sales Expenses**					
22						
23	**Sales-Operation**					
24	911 Supervision	-	-	-	-	-
25	912 Demonstrating & Selling			-	-	-
26	913 Advertising	553,862	68,971	484,891	513,230	-5.52%
27	916 Miscellaneous Sales	-	-	-	-	-
28	**Total Sales Expenses**	553,862	68,971	484,891	513,230	-5.52%
29						
30	**Administrative & General Expenses**					
31						
32	**Admin. & General-Operation**					
33	920 Admin. & General Salaries	32,598,843	4,293,846	28,304,997	25,561,455	10.73%
34	921 Office Supplies & Expenses	9,905,899	1,613,601	8,292,298	7,741,420	7.12%
35	922 Admin. Expense Transferred-Cr.	(6,082,785)	(1,979,941)	(4,102,844)	(3,811,026)	-7.66%
36	923 Outside Services Employed	4,927,614	979,169	3,948,445	4,909,102	-19.57%
37	924 Property Insurance	2,915,303	485,788	2,429,515	1,306,139	86.01%
38	925 Injuries & Damages	6,100,346	718,523	5,381,823	4,640,670	15.97%
39	926 Employee Pensions & Benefits	5,116,874	624,991	4,491,883	(1,829,276)	>300.00%
40	927 Franchise Requirements	-	-	-	-	-
41	928 Regulatory Commission Expenses	3,055,574	11,644	3,043,930	1,347,237	125.94%
42	929 Duplicate Charges-Cr.	-	-	-	-	-
43	930 Miscellaneous General Expenses	12,713,426	567,322	12,146,104	11,929,094	1.82%
44	931 Rents	2,223,462	415,547	1,807,915	1,833,512	-1.40%
45	**Total Operation-Admin. & General**	73,474,556	7,730,490	65,744,066	53,628,328	22.59%
46	**Admin. & General-Maintenance**					
47	935 General Plant	3,321,507	233,386	3,088,121	2,940,059	5.04%
48	**Total Maintenance-Admin. & General**	3,321,507	233,386	3,088,121	2,940,059	5.04%
49	**Total Admin. & General Expenses**	76,796,063	7,963,876	68,832,187	56,568,387	21.68%
50	**TOTAL OPER. & MAINT. EXPENSES**	$ 556,633,889	$ 111,879,181	$ 444,754,708	$ 505,262,801	-11.98%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$4,966,136	$4,462,619	11.28%
3	Property Taxes	94,839,541	75,068,049	26.34%
4	Electric Energy License Tax	1,201,288	590,175	103.55%
5	Crow Tribe RR and Utility Tax	50,748	41,074	23.55%
	Fort Peck	276	-	-
6	City Tax	6,763	9,007	-24.92%
7	Consumer Counsel Tax	552,502	639,211	-13.56%
8	Public Service Commission Tax	1,776,796	1,884,505	-5.72%
9	Heavy Highway Use Tax	16,995	13,640	24.60%
10	Vehicle Use Tax	202,290	165,687	22.09%
11	Wholesale Energy Transaction Tax	1,362,574	1,210,077	12.60%
12	Delaware Franchise Tax	108,030	104,429	3.45%
13				
14				
15				
16				
17	**TOTAL TAXES OTHER THAN INCOME**	$105,083,939	$84,188,473	24.82%
18				
19				

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A EXCAVATION	Excavation Contractor	227,216
2	AFFCO INC	Hydro Construction Services	1,197,609
3	ALME CONSTRUCTION, INC.	Construction	300,392
4	ALSTOM GRID INC	Software Support Services	305,058
5	AMERICAN INNOVATIONS INC	Software Support Services	94,857
6	AMERICAN PUBLIC LAND EXCHANGE	Environmental Consulting Services	354,816
7	ARCADIS US INC	Engineering Services	2,104,755
8	ASCEND ANALYTICS LLC	Hydro Expert Analysis	424,412
9	ASPLUNDH TREE EXPERT CO	Tree Trimming	4,828,599
10	ASSOCIATED ARBORISTS	Vegetation Management	677,199
11	ASSOCIATED UNDERWATER SERVICE	Hydro Repair services	85,549
12	AUTOMOTIVE RENTALS INC	Fleet Management	7,752,209
13	AVERY PIPELINE SERVICES INC	Craft Inspector Services	108,581
14	BAKER BOTTS LLP	Legal Services	166,291
15	BART ENGINEERING COMPANY	Engineering Services	502,123
16	BIG COUNTRY ENERGY SERVICES LL	Construction	121,701
17	BILL FIELD TRUCKING INC	Hauling Services	446,332
18	BISON ENGINEERING INC	Engineering Services	222,204
19	BOBCAT SPORTS PROPERTIES LLC	Fencing Installation	178,500
20	BOZEMAN GREEN BUILD	Solar System Installation	106,610
21	BROWNING, KALECZYC, BERRY & HO	Legal Services	104,749
22	BRYAN CAVE LLP	Legal Services	96,679
23	CENTRAL AIR SERVICE INC	Aerial Pilot Services	131,130
24	CENTRAL COPTERS INC	Flight Services	168,083
25	CENTRAL EXCAVATING AND MINI ST	Excavation Services	137,014
26	CENTRAL PLUMBING & HEATING INC	Construction	110,207
27	CENTRON SERVICES INC	Customer Collection Services	101,344
28	CESSNA AIRCRAFT COMPANY	Aircraft Maintenance	232,768
29	CLEARESULT CONSULTING INC	Energy Efficiency Consultants	595,446
30	COLUMBUS CONCRETE	Concrete and Asphalt Services	125,719
31	CONTINENTAL STEEL WORKS	Fabrication Services	1,159,519
32	CONTINUOUS POWER INNOVATIONS I	Service Agreement	398,724
33	CORPORATE EXECUTIVE BOARD	Organizational Development Consultant	141,860
34	CRIST, KROGH, BUTLER & NORD LL	Legal Services	203,206
35	CTA ARCHITECTS ENGINEERS	Energy Conservation Consultants	291,758
36	DAREN CONSTRUCTION INC	Construction	267,918
37	DAVEY TREE SURGERY COMPANY	Tree Trimming	2,195,588
38	DELOITTE & TOUCHE LLP	Audit Services	1,544,616
39	DELOITTE TAX LLP	Tax Services	190,671
40	DEPT OF HEALTH & HUMAN SERVICE	Weatherization Program Services	2,156,024
41	DEVLIN ENTERPRISES	Political Services	82,447
42	DGR ENGINEERING	Engineering Services	461,146
43	DICK ANDERSON CONSTRUCTION	Construction	14,056,930
44	DISTRIBUTION CONSTRUCTION CO	Gas Pipeline Construction	1,887,960
45	DJ&A P C CONSULTING ENGINEERS	Engineering Services	182,099
46	DONOVAN CONSTRUCTION	Construction	390,875
47	DORSEY & WHITNEY LLP	Legal Services	411,357
48	DOWL HKM	Geotechnical Services	76,433
49	E SOURCE COMPANIES LLC	Strategic Services	119,510
50	EAGLE GAS MARKETING LLC	Marketing Services	392,124
51	EAGLE LANDSCAPING	Landscape Services	106,071
52	ELECTRO-TEST & MAINTENANCE	Transformer Relocation Services	133,048
53	ELM LOCATING & UTILITY SERVICE	Locating Services and Excavation Notifications	2,677,306
54	ENERGY LABORATORIES INC	Soil Testing Services	88,668
55	ENERGY SHARE OF MONTANA	USBC Services	874,427
56	FALLS CONSTRUCTION COMPANY	Construction	273,592
57	FITCH INC	Debt Rating Services	252,000
58	FLUID MARKET STRATEGIES	Energy Conservation Consultants	106,027
59	FLYNN WRIGHT INC	Advertising Services	1,119,882
60	FORBES TATE PARTNERS LLC	Regulatory Consultants	120,000

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
61	FOUR O SIX UNDERGROUND INC	Boring Services	178,580
62	GARTNER INC	Information Technology Consulting	135,932
63	GE BETZ INC	Chemical Management Services	179,480
64	GEI CONSULTANTS INC	Environmental Consultants	218,281
65	GILLESPIE PRUDHON & ASSOCIATES	Telecommunications Engineers	457,893
66	GUY TABACCO CONSTRUCTION	Construction	164,346
67	H & H ASPHALT & MAINTENANCE IN	Asphalt Services	276,585
68	H & H CONTRACTING INC	Concrete and Asphalt Services	1,060,346
69	H2E INC	Engineering Services	140,129
70	HAIDER CONSTRUCTION INC	Backhoe Services	348,894
71	HDR ENGINEERING INC	Engineering Services	1,039,236
72	HEALTH FITNESS CORPORATION	Employee Wellness Program Management	316,278
73	HEATH CONSULTANTS INC	Gas Leak Surveys	495,077
74	HIGH MARK MEDIA	Marketing Services	100,420
75	HOWALT MCDOWELL INSURANCE INC	Benefits Consultants	98,576
76	IES COMMERCIAL INC	Construction	1,228,582
77	INTEC SERVICES INC	Pole Inspection	1,287,976
78	INTERGRAPH CORPORATION	Software Consultants	477,793
79	IRON PINE COMPANY LLC	Vegetation Management	102,725
80	J&J EXCAVATING & TRUCKING INC	Excavation Services	2,304,475
81	JACOBSEN TREE EXPERTS	Tree Trimming	956,398
82	JD ENGINEERING P C	Engineering Services	393,290
83	JONES DAY	Legal Services	259,849
84	JSSI JET SUPPORT SERVICES INC	Flight Services	232,525
85	KC HARVEY ENVIRONMENTAL LLC	Environmental Consultants	317,307
86	KELLY SERVICES INC	Engineering Services	82,305
87	KLEINSCHMIDT ASSOCIATES	Engineering Services	325,376
88	KM CONSTRUCTION CO INC	Construction	87,152
89	KNIFE RIVER	Construction	83,699
90	LANDS ENERGY CONSULTING	Energy Consultants	113,481
91	LARSON DIGGING INC	Excavation Services	353,384
92	LAST BEST PLACE LANDSCAPING IN	Landscape Services	167,900
93	LAWNS OF MONTANA	Landscape Services	86,910
94	LIEN TRANSPORTATION CO	Construction	351,011
95	LIQUID GOLD WELL SERVICE INC	Well Services	123,950
96	LOCKMER PLUMBING HEATING &	Gas Meter Relocations	351,853
97	M & P EXCAVATING LLP	Excavation Services	201,375
98	MAPPCOR	Electric Reliability Services	314,665
99	MARKOVICH CONSTRUCTION INC	Construction	158,000
100	MCMILLEN LLC	Construction	2,735,012
101	MERCER HUMAN RESOURCE CONSULTI	Human Resource Consulting	345,955
102	MERIDIAN IT INC	Information Technology Services	619,006
103	METALWORKS OF MONTANA	Roofing Services	256,311
104	MICROSOFT SERVICES	Computer Maintenance	97,690
105	MINUTEMAN AVIATION INC.	Charter Services	133,010
106	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	912,848
107	MOODY'S INVESTORS SERVICE	Debt Rating Services	483,750
108	MORAN IRON WORKS INC	Construction	531,900
109	MORRISON MAIERLE INC	Engineering Services	650,370
110	MOSAIC ARCHITECTURE	Construction	379,832
111	MOUNTAIN POWER CONSTRUCTION CO	Construction	18,979,355
112	MOUNTAIN WEST HOLDING COMPANY	Construction	548,417
113	MUTH ELECTRIC INC	Transformer Installation	122,402
114	NATIONAL CENTER FOR APPROPRIAT	Conservation Program Consultants	508,017
119	NAVIGANT CONSULTING INC	Transmission System Consultants	108,598
120	NCSG CRANE & HEAVY HAUL SERVIC	Heavy Haul Services	90,815
121	NEXANT INC	Energy Efficiency Consultants	264,386
122	NORLEY CONSULTING	Gas Compressor Consultant	149,211
123	NORTHWEST DYNAMICS INSPECTION	Safety Inspections	86,895
124	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,259,670
125	NORTHWEST TOWER	Construction	135,618
126	OMIMEX CANADA LTD	Gas Lease Operating Services	843,923
127	ONSITE ENERGY INC	Construction	77,602
129	OPEN ACCESS TECHNOLOGY INT'L I	Software Support Services	403,758

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
130	OSMOSE UTILITIES SERVICES INC	Construction	2,327,062
131	P2 ENERGY SOLUTIONS INC	Computer System Implementation	101,480
132	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	20,347,404
133	PEAKER SERVICES INC (PSI)	Generator Repair Services	83,357
134	PERKINS COIE	Legal Services	183,474
135	PIONEER TECHNICAL SERVICES INC	Engineering Services	130,964
136	POTEET CONSTRUCTION	Traffic Safety Services	105,058
137	POWER ENGINEERS	Engineering Services	249,074
137	POWERPLAN INC	Software Implementation Support Services	389,303
138	PRICEWATERHOUSECOOPERS LLP	Audit Services	223,910
139	PRO PIPE CORPORATION	Construction	1,553,085
140	PROPAK SYSTEMS LTD	Generator Repair Services	1,293,637
141	Q3 CONTRACTING INC	Construction	125,000
142	RESPEC	Right of Way Consulting Services	217,433
143	RML INCORPORATED	Boring Services	169,373
144	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	28,503,197
145	ROD TABBERT CONSTRUCTION INC	Construction	355,268
146	ROTHERHAM CONSTRUCTION	Construction	150,305
147	ROUNDS BROTHERS TRENCHING	Boring Services	507,443
148	RUSSELL REYNOLDS ASSOC INC	Executive Search Services	121,075
149	SHUMAKER TRUCKING & EXCAVATING	Excavation Contractor	77,710
150	SIDEWINDERS LLC	Generator Repair Services	171,612
151	SKADDEN, ARPS, SLATE, MEAGH	Legal Services	1,081,178
152	SLETTEN CONSTRUCTION COMPANY	Construction	1,026,603
153	SOUTHWEST POWER POOL	Transmission Services	1,871,812
154	SPHERION STAFFING	Temporary Employment Services	344,097
155	STANDARD & POOR'S FINANCIAL SE	Debt Rating Services	134,705
156	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	584,523
157	STEEL STRUCTURES LLC	Construction	78,000
158	STINSON LEONARD STREET LLP	Legal Services	788,694
159	TAMIETTI CONSTRUCTION COMPANY	Construction	309,365
160	THE CLARO GROUP LLC	Legal Services	92,202
161	THE CONFEDERATED SALISH AND	Cultural Resource Study	136,776
162	THE ELECTRIC COMPANY OF SOUTH	Construction	663,448
163	THE L E MYERS CO	Storm Damage Restoration	561,093
164	THE LAWN RANGER	Landscape Services	86,990
165	THE LYON FIRM PA	Legal Services	104,680
166	THOMPSON PAINTING & SANDBLASTI	Painting Services	79,930
167	TITAN ELECTRIC INC	Construction	85,598
168	TODD O BRUESKE CONSTRUCTION	Construction	506,776
169	TONY LASLOVICH CONSTRUCTION	Construction	80,727
170	TOWER SYSTEMS INC	Construction	89,697
171	TOWERS WATSON DELAWARE INC	Compensation Services	81,311
172	TRADEMARK ELECTRIC INC	Construction	750,759
173	ULTEIG ENGINEERS INC	Project Manager Services	312,905
174	UNITED STATES GEOLOGICAL SURVE	Environmental Consultants	198,000
175	URS ENERGY & CONSTRUCTION INC	Construction	105,334
176	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	141,514
177	UTILITY MAPPING SERVICES INC	Line Location Services	247,823
178	VAISALA INC	Environmental Consultants	109,288
179	VARSITY CONTRACTORS INC	Janitorial Services	308,109
180	VERTEX	Billing Services and System Implementation	2,803,725
181	VESTA PARTNERS LLC	Engineering Services	111,011
182	VOITH HYDRO POWER GENERATION	Generator Repair Services	181,090
183	WASHINGTON FORESTRY CONSULTANT	Forestry Consultants	459,041
184	WATSON TRUCKING	Water Hauling Services	135,630
185	WHALEN TIRE INC	Tire Inspection Services	86,719
186	WINN-MARION INC	Legal Services	331,721
187	WOOD GROUP PRATT & WHITNEY LLC	Turbine Repair Services	134,136
188			
189			
190			
191			
192			
	Total of Payments Set Forth Above		$ 173,257,547

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

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

Sch. 14	Pension Costs 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code:		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 621,367,413	$ 510,163,556	21.80%
8	Service cost	11,211,631	9,792,283	14.49%
9	Interest cost	23,790,829	23,633,207	0.67%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	(43,302,089)	97,569,854	-144.38%
13	Acquisition	-	-	-
14	Benefits paid	(47,706,492)	(19,791,487)	-141.05%
15	Benefit obligation at end of year	$ 565,361,292	$ 621,367,413	-9.01%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 496,012,024	$ 459,232,101	8.01%
18	Actual return on plan assets	(14,678,061)	47,571,410	-130.85%
19	Acquisition	-	-	-
20	Employer contribution	9,000,000	9,000,000	
21	Plan participants' contributions	-	-	-
22	Benefits paid	(47,706,492)	(19,791,487)	-141.05%
23	Fair value of plan assets at end of year	$ 442,627,471	$ 496,012,024	-10.76%
24	**Funded Status**	$ (122,733,821)	$ (125,355,389)	2.09%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (122,733,821)	$ (125,355,389)	2.09%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	4.30%	3.90%	10.26%
32	Expected return on plan assets	5.80%	5.80%	
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	$ 11,211,631	$ 9,792,283	14.49%
36	Interest cost	23,790,829	23,633,207	0.67%
37	Expected return on plan assets	(28,232,855)	(26,316,885)	-7.28%
38	Amortization of prior service cost	246,361	246,361	
39	Recognized net actuarial gain	10,298,339	2,117,774	>300.00%
40	Net periodic benefit cost (SEC Basis)	$ 17,314,305	$ 9,472,740	82.78%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 9,000,000	$ 9,000,000	
43	Pension Costs Capitalized	1,821,176	1,822,578	-0.08%
44	Accumulated Pension Asset (Liability) at Year End	$ (122,733,821)	$ (125,355,389)	2.09%
45	Number of Company Employees:			
46	Covered by the Plan	3,086	3041	1.48%
47	Not Covered by the Plan 2/	520	441	17.91%
48	Active 2/	880	860	2.33%
49	Retired	1,498	1432	4.61%
50	Deferred Vested Terminated	708	749	-5.47%

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; however, the number of eligible active participants increased from 860 to 880 due to the additional PPL Montana, LLC employees who became eligible to participate in the plan on November 18, 2014.

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	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest cost			
10	Plan participants' contributions	Not Applicable		
11	Amendments			
12	Actuarial loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year	$ -	$ -	
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 329,680,178	$ 312,279,277	-5.28%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 9,450,630	$ 8,715,756	8.43%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 320,552,638	$ 329,680,178	-2.77%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 6,942,301	$ 6,258,247	10.93%
44	401(k) Plan Defined Contribution Costs Capitalized	1,404,794	1,267,349	10.85%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1589	1,587	0.13%
48	Not Covered by the Plan			
49	Active - Participating	1549	1,537	0.78%
50	Retired			
51	Vested Former Employees, Retirees and Active-	244	259	-5.79%
52	Noncontributing			
	2/ This plan covers all NorthWestern Corporation employees.			
	3/ Represents total company 401(k) plan participants.			

Sch. 15	Other Post Employment Benefits (OPEBS)			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2012.9.94			
4	Order number: 7249e			
5	Amount recovered through rates	($90,216)	($101,920)	11.48%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	3.60%	3.20%	12.50%
8	Expected return on plan assets	5.80%	5.80%	
9	Medical Cost Inflation Rate 3/	7.94%,4.5%:23	8.0%,4.5%:14	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	Describe any Changes to the Benefit Plan:			
16				
	The hydro generation facility group participant data and benefit provisions are incorporated in the 2015 valuation.			

1/ Obtained from NorthWestern Energy-Montana's 2014 FASB 106 Valuation. Assumptions and data are as of December 31, 2015.
2/ Obtained from NorthWestern Energy-Montana's 2014 FASB 106 Valuation. Assumptions and data are as of December 31, 2014.
3/ First Year, Ultimate, Years to Reach Ultimate.

Sch. 15a	Other Post Employment Benefits (OPEBS) (continued)			
	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active			
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$20,967,136	$20,677,119	1.40%
10	Service cost	430,615	374,530	14.97%
11	Interest Cost	687,100	743,834	-7.63%
12	Plan participants' contributions	606,124	576,792	5.09%
13	Amendments 5/	1,044,607	-	-
14	Actuarial loss/(gain)	(308,969)	896,216	-134.47%
15	Acquisition	-	-	-
16	Benefits paid	(2,641,956)	(2,301,355)	-14.80%
17	Benefit obligation at end of year	$20,784,657	$20,967,136	-0.87%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$18,040,317	$18,183,195	-0.79%
20	Actual return on plan assets	479	1,390,832	-99.97%
21	Acquisition	-	-	-
22	Employer contribution	1,967,960	190,853	>300.00%
23	Plan participants' contributions	606,124	576,792	5.09%
24	Benefits paid	(2,641,956)	(2,301,355)	-14.80%
25	Fair value of plan assets at end of year	$17,972,924	$18,040,317	-0.37%
26	**Funded Status**	($2,811,733)	($2,926,819)	3.93%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	($2,811,733)	($2,926,819)	3.93%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$430,615	$374,530	14.97%
33	Interest cost	687,100	743,834	-7.63%
34	Expected return on plan assets	(968,659)	(980,569)	1.21%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,032,848)	(2,148,915)	5.40%
37	Recognized net actuarial loss/(gain)	384,803	347,876	10.61%
38	Net periodic benefit cost	($1,498,989)	($1,663,244)	9.88%
39	**Accumulated Post Retirement Benefit Obligation**		-	
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	1,967,960	190,853	>300.00%
43	TOTAL	$1,967,960	$190,853	>300.00%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(90,216)	(101,920)	11.48%
47	TOTAL	($90,216)	($101,920)	11.48%
48	**Montana Intrastate Costs:**			
49	Pension Costs	($90,216)	($101,920)	11.48%
50	Pension Costs Capitalized	(18,255)	(20,640)	11.55%
51	Accumulated Pension Asset (Liability) at Year End	(2,811,733)	(2,926,819)	3.93%
52	**Number of Montana Employees:**		-	
53	Covered by the Plan	1,927	1,913	0.73%
54	Not Covered by the Plan	106	92	15.22%
55	Active	895	887	0.90%
56	Retired	929	932	-0.32%
57	Spouses/Dependants covered by the Plan	103	94	9.57%

4/ There is approximately an additional $7,867,997 and $9,037,879 in other company OPEBS liabilities outstanding at December 31, 2015 and 2014, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

5/ Amendment portion of change in benefit obligation was largely due to the addition of PPL Montana, LLC employees who became eligible to participate in the plan on November 18, 2014.

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	John D. Hines Vice President, Supply	238,430	70,019 A	19,655 B 120,706 C 6,001 D 32,622 E	487,433	532,012	-8%
2	Michael R. Cashell Vice President, Transmission	238,430	70,019 A	33,101 B 120,706 C 5,964 D 9,703 E	477,923	702,005	-32%
3	Kendall Kliewer Former Vice President & Controller	248,694	70,200 A	47,173 B 97,372 C 4,791 E	468,230	561,754	-17%
4	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	241,422	70,009 A	27,444 B 125,080 C	463,955	697,236	-33%
5	Daniel L. Rausch Treasurer	199,929	43,234 A	48,108 B 48,920 C 7,056 D 3,905 E 20,000 F	371,152	383,935	-3%
6	Michael L. Nieman Chief Audit and Compliance Officer	210,361	45,489 A	50,419 B 51,468 C 878 E	358,615	407,318	-12%
7	William T. Rhoads General Manager, Generation	182,629	32,728 A	24,681 B 35,756 C 3,094 D 20,983 E 20,000 F	319,871	511,022	-37%
8	Jeanne M. Vold Business Technology Officer	182,078	43,715 A	26,681 B 44,546 C 4,586 E 5,000 F	306,606	320,722	-4%
9	Wayne M. Hitt Director, Tax	162,644	27,415 A	42,457 B 31,849 C 15,000 F 375 G	279,740	279,423	0%
10	Timothy P. Olson Corporate Counsel & Corp Secretary	166,615	30,381 A	42,492 B 32,401 C 5,000 F	276,889	272,730	2%

EMPLOYEES (ASSIGNED OR ALLOCATED)

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2015 Annual Incentive Compensation Plan. Amounts were earned in 2015 and paid in the first quarter of 2016. Based on company performance against plan, the incentive plan was funded at 80% of target for executives and 88% for non executives. Individual awards varied from the funded level based on individual performance.

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

B> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, Health Savings Account, wellness incentive, 401(k) match, and non-elective 401(k) contribution.

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

D> Vacation sold back during the year.

E> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2015.

F> Merit cash payment

G> Imputed income related to company facilities.

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	573,567	370,068 A	23,913 B 1,131,121 C 39,285 D 41 E 17,610 F	2,155,605	2,342,841	-8%
2	Brian B. Bird Vice President & Chief Financial Officer	391,181	159,981 A	49,677 B 468,227 C 9,264 D	1,078,330	1,099,373	-2%
3	Heather H. Grahame Vice President & General Counsel	346,032	126,075 A	48,360 B 304,597 C	825,064	846,147	-2%
4	Curtis T. Pohl Vice President, Distribution	269,577	86,966 A	52,091 B 212,661 C 5,814 D 7,611 F	634,720	727,016	-13%
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	248,530	70,154 A	49,823 B 134,849 C 5,012 D	508,368	559,336	-9%

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 2015 Annual						
4	Incentive Compensation Plan. Amounts were earned in 2015 and paid in the first quarter of 2016. Based on company						
5	performance against plan, the incentive plan was funded at 80% of target for executives and 88% for non-executives.						
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, 2015.						
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	**Assets and Other Debits**				
2	**Utility Plant**				
3	101 Plant in Service	$5,133,213,168	$4,612,121,385	$521,091,783	11.30%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	-	0.00%
5	103 Experimental Electric Plant Unclassified	658,807	-	658,807	-
6	105 Plant Held for Future Use	3,783,001	3,558,413	224,588	6.31%
7	107 Construction Work in Progress	63,741,643	213,126,467	($149,384,824)	-70.09%
8	108 Accumulated Depreciation Reserve	(1,766,993,982)	(1,690,819,946)	($76,174,036)	4.51%
9	108.1 Accumulated Depreciation - Capital Leases	(19,099,502)	(17,089,022)	($2,010,480)	11.76%
10	111 Accumulated Amortization & Depletion Reserves	(45,773,447)	(37,112,782)	($8,660,665)	23.34%
11	114 Electric Plant Acquisition Adjustments	380,714,172	350,132,657	30,581,515	8.73%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(8,239,513)	(937,002)	(7,302,511)	>300.00%
13	116 Utility Plant Adjustments	357,585,527	355,128,500	2,457,027	0.69%
14	117 Gas Stored Underground-Noncurrent	32,117,397	32,135,879	(18,482)	-0.06%
15	**Total Utility Plant**	4,171,916,808	3,860,454,086	311,462,722	8.07%
16	**Other Property and Investments**				
17	121 Nonutility Property	6,749,606	6,749,606	-	0.00%
18	122 Accumulated Depr. & Amort.-Nonutility Property	(1,492,272)	(1,154,851)	(337,421)	29.22%
19	123.1 Investments in Assoc Companies and Subsidiaries	(135,251,446)	(140,450,323)	5,198,877	-3.70%
20	124 Other Investments	42,541,769	39,899,904	2,641,865	6.62%
21	128 Miscellaneous Special Funds	855,040	16,787,692	(15,932,652)	-94.91%
22	LT Portion of Derivative Assets - Hedges	-	-	-	-
23	**Total Other Property & Investments**	(86,597,303)	(78,167,972)	(8,429,331)	10.78%
24	**Current and Accrued Assets**				
25	131 Cash	4,085,198	12,841,079	(8,755,881)	-68.19%
26	134 Other Special Deposits	3,508,309	10,528,068	(7,019,759)	-66.68%
27	135 Working Funds	22,934	42,575	(19,641)	-46.13%
28	136 Temporary Cash Investments	-	-	-	-
29	141 Notes Receivable	-	-	-	-
30	142 Customer Accounts Receivable	73,702,625	83,662,524	(9,959,899)	-11.90%
31	143 Other Accounts Receivable	12,243,185	16,550,278	(4,307,093)	-26.02%
32	144 Accumulated Provision for Uncollectible Accounts	(3,998,768)	(4,301,616)	302,848	-7.04%
33	145 Notes Receivable-Associated Companies	-	-	-	-
34	146 Accounts Receivable-Associated Companies	485,808	344,565	141,243	40.99%
35	151 Fuel Stock	8,240,873	7,630,351	610,522	8.00%
36	154 Plant Materials and Operating Supplies	30,372,676	29,082,484	1,290,192	4.44%
37	164 Gas Stored - Current	13,111,331	16,360,518	(3,249,187)	-19.86%
38	165 Prepayments	7,664,332	13,818,312	(6,153,980)	-44.53%
39	171 Interest and Dividends Receivable	-	-	-	-
41	172 Rents Receivable	59,037	204,569	(145,532)	-71.14%
42	173 Accrued Utility Revenues	74,456,572	70,315,316	4,141,256	5.89%
43	174 Miscellaneous Current & Accrued Assets	19,175	30,019,535	(30,000,360)	-99.94%
44	175 Derivative Instrument Assets (175)	-	-	-	100.00%
45	(Less) Long-Term Portion of Derivative Instrument Assets	-	-	-	-
46	176 LT Portion of Derivative Assets - Hedges	-	-	-	-
47	(less) LT Portion of Derivative Assets - Hedges	-	-	-	-
48	**Total Current & Accrued Assets**	223,973,287	287,098,558	(63,125,271)	-21.99%
49	**Deferred Debits**				
50	181 Unamortized Debt Expense	13,944,763	13,041,834	902,929	6.92%
51	182 Regulatory Assets	522,719,480	463,907,330	58,812,150	12.68%
52	183 Preliminary Survey and Investigation Charges	1,185,617	1,185,617	-	0.00%
53	184 Clearing Accounts	3,239	900	2,339	259.89%
54	185 Temporary Facilities	-	-	-	-
55	186 Miscellaneous Deferred Debits	164,979	530,880	(365,901)	-68.92%
56	189 Unamortized Loss on Reacquired Debt	19,978,298	12,151,208	7,827,090	64.41%
57	190 Accumulated Deferred Income Taxes	201,297,196	186,187,313	15,109,883	8.12%
58	191 Unrecovered Purchased Gas Costs	25,765,650	25,520,064	245,586	0.96%
59	**Total Deferred Debits**	785,059,222	702,525,146	82,534,076	11.75%
60	**TOTAL ASSETS and OTHER DEBITS**	$ 5,094,352,014	$ 4,771,909,818	$ 322,442,196	6.76%

Sch. 18	cont. BALANCE SHEET 1/				
	Account Title	This Year	This Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 517,894	$ 505,226	$ 12,668	2.51%
4	204 Preferred Stock Issued	-	-	-	-
5	207 Premium on Capital Stock	-	-	-	-
6	211 Miscellaneous Paid-In Capital	1,376,291,019	1,313,844,035	62,446,984	4.75%
7	213 Discount on Capital Stock	-	-	-	-
8	214 Capital Stock Expense	-	-	-	-
9	215 Appropriated Retained Earnings	-	-	-	-
10	216 Unappropriated Retained Earnings	325,909,358	264,757,908	61,151,450	23.10%
12	217 Reacquired Capital Stock	(93,948,186)	(92,558,283)	(1,389,903)	1.50%
13	219 Accumulated Other Comprehensive Income	(8,596,115)	(8,765,944)	169,829	-1.94%
14	**Total Proprietary Capital**	1,600,173,970	1,477,782,942	122,391,028	8.28%
15	**Long Term Debt**				
16	221 Bonds	1,755,205,000	1,635,205,000	120,000,000	7.34%
17	223 Advances in Associated Companies	-	-	-	-
18	224 Other Long Term Debt	26,976,900	26,976,900	-	0.00%
19	226 (Less) Unamortized Discount on Long Term Debt-Debit	54,438	83,438	(29,000)	-34.76%
20	**Total Long Term Debt**	1,782,127,462	1,662,098,462	120,029,000	7.22%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	26,325,495	28,162,445	(1,836,950)	-6.52%
23	228.1 Accumulated Provision for Property Insurance	-	-	-	-
24	228.2 Accumulated Provision for Injuries and Damages	8,642,245	9,061,051	(418,806)	-4.62%
25	228.3 Accumulated Provision for Pensions and Benefits	19,558,642	20,244,171	(685,529)	-3.39%
26	228.4 Accumulated Miscellaneous Operating Provisions	169,001,631	164,953,264	4,048,367	2.45%
27	229 Accumulated Provision for Rate Refunds	55,190,626	34,280,250	20,910,376	61.00%
28	230 Asset Retirement Obligations	35,532,209	21,435,223	14,096,986	65.77%
29	**Total Other Noncurrent Liabilities**	314,250,848	278,136,404	36,114,444	12.98%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	229,874,444	267,840,079	(37,965,635)	-14.17%
32	232 Accounts Payable	81,679,866	90,659,542	(8,979,676)	-9.90%
33	233 Notes Payable to Associated Companies	-	-	-	-
34	234 Accounts Payable to Associated Companies	1,525,951	1,466,006	59,945	4.09%
35	235 Customer Deposits	6,608,591	6,621,535	(12,944)	-0.20%
36	236 Taxes Accrued	44,567,955	39,264,570	5,303,385	13.51%
37	237 Interest Accrued	21,400,048	19,734,213	1,665,835	8.44%
39	238 Dividends Declared	-	-	-	-
40	241 Tax Collections Payable	1,353,247	1,892,527	(539,280)	-28.50%
41	242 Miscellaneous Current and Accrued Liabilities	52,760,668	63,800,309	(11,039,641)	-17.30%
42	243 Obligations Under Capital Leases-Current	1,836,946	1,729,507	107,439	6.21%
43	244 Derivative Instrument Liabilities	-	-	-	-
44	245 Derivative Instrument Liabilities - Hedges	-	18,310,043	(18,310,043)	-100.00%
45	**Total Current and Accrued Liabilities**	441,607,716	511,318,331	(69,710,615)	-13.63%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	36,045,534	30,000,627	6,044,907	20.15%
48	253 Other Deferred Credits	169,368,167	171,200,388	(1,832,221)	-1.07%
49	254 Regulatory Liabilities	29,521,568	26,470,224	3,051,344	11.53%
50	255 Accumulated Deferred Investment Tax Credits	356,380	588,781	(232,401)	-39.47%
51	257 Unamortized Gain on Reacquired Debt	-	-	-	-
52	281-283 Accumulated Deferred Income Taxes	720,900,369	614,313,659	106,586,710	17.35%
53	**Total Deferred Credits**	956,192,018	842,573,679	113,618,339	13.48%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 5,094,352,014	$ 4,771,909,818	$ 322,442,196	6.76%
55					
56	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory				
57	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the				
58	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian				
59	Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.				
60					
61					
62					
63					
64					Schedule 18A

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 701,000 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 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. Our November 2014 acquisition of hydro generating assets is included in the results of operations for the years ended December 31, 2015 and 2014, and impacts the comparability of the current year financial statements to prior years. For a further discussion of this acquisition, see Note 3 - Acquisitions.

(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 $368.5 million and $351.7 million as of December 31, 2015 and December 31, 2014, 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 $357.6 million and $355.1 million as of December 31, 2015 and December 31, 2014, 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, 2015 and December 31, 2014, 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 a net non-current deferred tax liability;
- Uncertain tax positions related to temporary differences are classified in the Balance Sheets within the deferred tax accounts in accordance with regulatory treatment, as compared to other noncurrent liabilities for GAAP purposes;
- 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 $4.0 million and $4.3 million at December 31, 2015 and December 31, 2014, respectively. Unbilled revenues were $74.5 million and $70.3 million at December 31, 2015 and December 31, 2014, respectively.

Inventories

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

	December 31,	
	2015	2014
Fuel stock	$8,241	$7,630
Plant materials and operating supplies	30,373	29,082
Gas stored underground (including the non-current portion reflected in utility plant)	45,229	48,496
Total Inventory	**$83,843**	**$85,208**

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 deemed probable 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 are designated as normal purchases and normal sales 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 7.5% and 8.0% for Montana and South Dakota for 2015 and 2014, respectively. AFUDC capitalized totaled $13.6 million for the year ended December 31, 2015 and $10.8 million for the year ended December 31, 2014 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 3.3% and 2.9% for 2015 and 2014, 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 and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if 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

The acquisition of hydro generating assets and the Beethoven wind project 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 - Acquisitions.

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 FASB delayed the effective date of this guidance to the first quarter of 2018, with early adoption permitted as of the original effective date of the first quarter of 2017. We are currently evaluating the impact of adoption of this new guidance on our Financial Statements and disclosures.

Accounting Standards Adopted

In May 2015, the FASB issued accounting guidance that removed the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and certain disclosures related to those investments. We early adopted this standard in the fourth quarter of 2015. As a result, net asset value investments are no longer included in Level 2 and Level 3 within the fair value hierarchy.

(3) Acquisitions

Hydro Transaction

In November 2014, we completed the purchase of 11 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 provides long-term supply diversity to our portfolio and reduces risks associated with variable fuel prices. The Hydro Transaction allows 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 are less exposed to market volatility and better positioned to control the cost of supplying electricity to our customers. We completed the purchase accounting in 2015 and, as a result, increased utility plant adjustments by approximately $2.5 million primarily due to our assessment of environmental matters.

Kerr Project - The Hydro Transaction included the Kerr Project. Upon the close of the Hydro Transaction, we assumed temporary ownership of the Kerr Project until it was conveyed to the Confederated Salish and Kootenai Tribes of the Flathead Reservation (CSKT) on September 5, 2015, in accordance with the associated FERC license. Our purchase agreement for the Hydro Transaction included a $30 million reference price for the Kerr Project. In September 2015, the CSKT paid us $18.3 million, which was established through previous arbitration, and Talen Energy (formerly PPL Montana) paid the difference of $11.7 million to us. Upon receipt of the CSKT payment we conveyed the Kerr Project to the CSKT.

The Montana Public Service Commission (MPSC) order approving the Hydro Transaction provided that customers would 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. We sold any excess system generation, which was primarily due to our temporary ownership of the Kerr Project, in the market and provided revenue credits to our Montana retail customers until the transfer to the CSKT. Therefore, during our temporary ownership a net benefit of approximately $2.7 million was provided to customers and there was no benefit to shareholders. For further discussion of the required compliance filing see Note 4 - Regulatory Matters.

South Dakota Wind Generation

In September 2015, we completed the purchase of the 80 MW Beethoven wind project near Tripp, South Dakota, for approximately $143 million. The Beethoven project was not submitted in the South Dakota electric rate filing made in December 2014; however, we reached a stipulated settlement agreement in September 2015 that allowed us to include Beethoven in rate base and collect approximately $9.0 million annually.

The Beethoven 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

Assets Acquired	
Utility Plant	$143.0
Prepayments	$0.1
Total Assets Acquired	$143.1
Liabilities Assumed	
Miscellaneous Current and Accrued Liabilities	$0.3
Total Liabilities Assumed	$0.3
Total Purchase Price	$142.8

The purchase accounting was completed during the fourth quarter of 2015. The pro forma results as if the Beethoven acquisition occurred on January 1, 2015 would not be materially different from our financial results for the twelve months ended December 31, 2015.

(4) Regulatory Matters

Montana Electric and Natural Gas Tracker Filings

Each year we submit an electric and 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 Montana Public Service Commission (MPSC) reviews such filings and makes its cost recovery determination based on whether or not our supply procurement activities were prudent.

Electric Tracker - Our 2012/2013 and 2013/2014 tracker periods are part of consolidated dockets. The 2013/2014 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 Colstrip Unit 4 outage costs. During a June 2014 MPSC work session, these incremental market purchases related to the Colstrip Unit 4 outage were identified by the MPSC for additional prudency review.

For the 2014/2015 electric supply tracker, we reached a Stipulation and Settlement Agreement in November 2015 between us and the Montana Consumer Counsel (MCC) (Electric Stipulation), which requires us to include a $0.7 million reduction for production tax credits, suspend certain types of hedging of purchase power costs without first obtaining approval from the MPSC, and to make a compliance filing to remove lost revenues from electric rates effective December 1, 2015.

The MPSC held a work session in March 2016 and, in a 3 - 2 decision, directed staff to draft a final order in the 2012/2013 and 2013/2014 consolidated tracker docket disallowing both replacement power costs from the outage at Colstrip Unit 4 and costs related to generation portfolio modeling. The MPSC also directed staff to draft an order in the 2014/2015 tracker addressing the Electric Stipulation and disallowing modeling costs. Based on this March 2016 oral decision, we recorded a disallowance totaling approximately $10.3 million, which includes $8.2 million of replacement power costs and $2.1 million of modeling costs, and is reflected in operation expenses in the Statement of Income for the three months ended March 31, 2016. In April 2016, we received a final written order in the 2014/2015 tracker consistent with the oral decision, and expect the MPSC to issue a final order in the consolidated 2012/2013 and 2013/2014 tracker dockets in the second quarter of 2016. We will evaluate our legal options once we receive a final written order in the consolidated docket.

Natural Gas Tracker - In October 2015, we received a final order in the natural gas consolidated 2013/2014 and 2012/2013 tracker docket, which allows us to continue collecting the cost of service for natural gas production interests acquired in December 2013 and in August 2012 in northern Montana's Bear Paw Basin (Bear Paw) on an interim basis until approval is received for inclusion of these assets in rate base. The MPSC final order requires that we revise the bridge rates currently used to reflect expected 2015 fixed cost revenue requirements, and to make a filing by September 2016 to address the cost-recovery of our gas production fields. As of March 31, 2016, we have deferred revenue of approximately $0.8 million consistent with the final order.

For the 2014/2015 natural gas supply tracker, we reached a Stipulation and Settlement Agreement between us and the MCC, which requires us to refund our customers approximately $1.5 million as a result of revising the Bear Paw bridge rates to our expected 2015 fixed cost requirements through October 2015, which was recorded as a regulatory liability during 2015. The MPSC issued a final order approving the Stipulation and Settlement Agreement during the first quarter of 2016.

Electric and Natural Gas Lost Revenue Adjustment Mechanism - In 2005, the MPSC approved an energy efficiency program, by which we recovered on an after-the-fact basis a portion of our fixed costs that would otherwise have been collected in kilowatt hour sales lost due to the implementation of energy saving measures between rate filings in our supply trackers. In an order issued in October 2013 related to our 2011/2012 electric supply tracker, the MPSC required us to lower the calculated lost revenue recovery and imposed a new burden of proof on us for future recovery. We appealed the October 2013 order to Montana District Court, which led to a docket being initiated in June 2014 by the MPSC to review lost revenue policy issues. In October 2015, the MPSC issued an order to eliminate the lost revenue adjustment mechanism prospectively effective December 1, 2015.

Based on the October 2013 MPSC order, we have recognized $7.1 million of lost revenues for each annual electric supply tracker period (July 1, 2012 through November 30, 2015) and deferred the remaining portion, which is approximately $13.4 million as of March 31, 2016, and is recorded within accumulated provision for rate refunds in the Balance Sheets. 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 more than we have deferred or approve recovery of more DSM lost revenues than we have recognized since July 2012.

Hydro Compliance Filing

In December 2015, we submitted the required hydro compliance filing to remove the Kerr Project from cost of service, adjust for actual revenue credits and increase property taxes to actual amounts. In January 2016, the MPSC approved an interim adjustment to our hydro rates based on the compliance filing, and opened a separate contested docket requesting additional detail on the adjustment to rates due to the conveyance of the Kerr Project. The MCC has not filed testimony in this contested docket, however, the MPSC identified additional issues and requested information. We expect the MPSC to issue a final order during the second half of 2016. Due to the timing of the rate adjustment, as of March 31, 2016, we have deferred revenue of approximately $6.9 million that will be refunded to customers in 2016.

Dave Gates Generating Station at Mill Creek (DGGS)

In April 2014, the Federal Energy Regulatory Commission (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 that only a portion of these costs should be allocated to FERC jurisdictional customers. We have been recognizing revenue consistent with the ALJ's initial decision. As of March 31, 2016, 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. 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 would likely extend into 2017 or beyond.

The FERC order was assessed as a triggering event as to whether an impairment charge should be recorded with respect to DGGS. As of March 31, 2016, the DGGS net utility plant is approximately $159 million. DGGS previously provided only regulation and balancing service, which is the basis for the cost allocation in our filings. The addition of owned hydro generation is driving a shift in utilization of DGGS. In support of our biennial electricity supply resource procurement plan that we filed with the MPSC in March 2016, we conducted a portfolio optimization analysis to evaluate options to use DGGS in combination with other generation resources. This analysis indicates DGGS provides cost-effective products necessary to operate our Montana electricity portfolio, including regulation, load following, peaking services and other ancillary products such as operating reserves, which should guide future cost recovery. The cost recovery of 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.

(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,	
	2015	2014
Colstrip Unit 4 Basis Adjustment	$ (153,718)	$ (156,806)
Havre Pipeline Company, LLC	15,054	12,912
NorthWestern Services, LLC	1,899	1,883
Risk Partners Assurance, Ltd.	1,514	1,561
Total Investments in Subsidiary Companies	**$ (135,251)**	**$ (140,450)**

(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, 2015	2014
			(in thousands)	
Pension	17	Undetermined	$ 135,057	$ 139,050
Employee related benefits	17	Undetermined	21,055	19,080
Distribution infrastructure projects		2 Years	6,272	9,407
Environmental clean-up	20	Various	14,237	13,741
Income taxes	15	Plant Lives	319,973	263,764
State & local taxes & fees		Various	7,715	5,307
Other	—	Various	18,410	13,558
Total Regulatory Assets			**$ 522,719**	**$ 463,907**
Gas storage sales		24 Years	9,990	10,410
Unbilled revenue		1 Year	10,808	10,877
Environmental clean-up		Various	7,121	2,533
State & local taxes & fees		1 Year	1,566	511
Other		Various	37	2,139
Total Regulatory Liabilities			**$ 29,522**	**$ 26,470**

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 20 - 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 in property taxes 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 revenues.

(7) Utility Plant

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

	December 31,	
	2015	2014
	(in thousands)	
Land and improvements	$ 142,154	$ 137,098
Building and improvements	397,883	345,451
Storage, distribution, and transmission	3,066,824	2,769,946
Generation	1,696,141	1,483,137
Construction work in process	63,742	213,126
Other	255,576	270,390
Total utility plant	5,622,320	5,219,148
Less accumulated depreciation	(1,840,106)	(1,745,959)
Net utility plant	$ 3,782,214	$ 3,473,189

In 2014, we acquired hydro generating assets which resulted in an increase of approximately $870 million in utility plant. In 2015, we acquired the Beethoven wind project, which resulted in an increase of approximately $143 million in utility plant. For both acquisitions, 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 $21.3 million and $23.4 million as of December 31, 2015 and 2014, respectively, which included $21.1 million and $23.1 million as of December 31, 2015 and 2014, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as an obligation under capital lease.

Jointly Owned Electric Generating Plant

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

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

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2015				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 153,740	$ 60,088	$ 46,387	$ 289,604
Accumulated depreciation	37,522	27,940	37,160	73,328
December 31, 2014				
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

(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 utility plant and asset retirement obligations. 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,	
	2015	2014
Liability at January 1,	$ 21,435	$ 20,886
Accretion expense	1,437	1,073
Liabilities incurred	12,682	552
Liabilities settled	(22)	(85)
Revisions to cash flows	—	(991)
Liability at December 31,	$ 35,532	$ 21,435

The EPA's rule regulating Coal Combustion Residuals (CCRs) became effective in October 2015. The rule imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plants and not closed. Based on our assessment of these requirements, we recorded an increase to our existing AROs of approximately $12.0 million during the second quarter of 2015. See Note 20 - Commitments and Contingencies for further discussion of these requirements.

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, 2015 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.

Utility plant adjustments increased $2.5 million during the year ended December 31, 2015, due to the finalization of our assessment of environmental matters as part of the Hydro Transaction.

(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. 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 normal purchase and normal sale scope exception (NPNS) 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 unrealized amounts recorded in the Financial Statements at December 31, 2015 and 2014. 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

We have previously used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. We have no interest rate swaps outstanding. These swaps were designated as cash flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in accumulated other comprehensive income (AOCI). We reclassify these gains from AOCI into interest on long-term debt during the periods in which the hedged interest payments occur. The following table shows the effect of these 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, 2015
Interest rate contracts	Interest on long-term debt	$ 1,125

A net pre-tax loss of approximately $14.9 million is remaining in AOCI as of December 31, 2015, and we expect to reclassify approximately $0.3 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.

(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, 2015	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Other special deposits	$ 3,508	$ —	$ —	$ —	$ 3,508
Rabbi trust investments	24,245	—	—	—	24,245
Total	**$ 27,753**	**$ —**	**$ —**	**$ —**	**$ 27,753**
December 31, 2014					
Other special deposits	$ 10,528	$ —	$ —	$ —	$ 10,528
Rabbi trust investments	21,594	—	—	—	21,594
Total	**$ 32,122**	**$ —**	**$ —**	**$ —**	**$ 32,122**

Other special deposits represents 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, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 1,782,128	$ 1,844,974	$ 1,662,099	$ 1,817,642

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):

	2015		2014	
Notes Payable	Balance	Interest Rate	Balance	Interest Rate
Commercial Paper	$ 229.9	0.82%	$ 267.8	0.50%

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

	2015	2014
Maximum notes payable outstanding	$ 267.8	$ 276.9
Average notes payable outstanding	$ 192.8	$ 132.5
Weighted-average interest rate	0.61%	0.39%

Under our commercial paper program we may issue unsecured commercial paper notes on a private placement basis up to a maximum aggregate amount outstanding at any time of $340 million to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Commercial paper issuances are supported by available capacity under our unsecured revolving credit facility.

Unsecured Revolving Line of Credit

We have a $350 million unsecured revolving credit facility in place that does not amortize and is scheduled to expire on November 5, 2018. The facility bears interest at the lower of prime or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%. 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, 2015. Commitment fees for the unsecured revolving line of credit were $0.4 million for each of the years ended December 31, 2015 and 2014.

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.

(13) Long-Term Debt

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

	Due	December 31, 2015	December 31, 2014
Unsecured Debt:			
Unsecured Revolving Line of Credit	2018	$ —	$ —
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	55,000	55,000
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.26%	2040	70,000	—
Montana—6.04%		—	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	450,000
Montana—3.11%	2025	75,000	—
Montana—4.11%	2045	125,000	—
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
Other Long Term Debt:			
New Market Tax Credit Financing—1.146%	2046	26,977	26,977
Discount on Notes and Bonds	—	(54)	(83)
		$ 1,782,128	$ 1,662,099

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota First 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.

During September 2015, we issued $70 million of South Dakota First Mortgage Bonds at a fixed interest rate of 4.26% maturing in 2040 to finance the Beethoven wind project. 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.

In June 2015, we issued $200 million aggregate principal amount of Montana First Mortgage Bonds, which includes $75 million at a fixed interest rate of 3.11% maturing in 2025 and $125 million at a fixed interest rate of 4.11% maturing in 2045. The bonds are secured by our electric and natural gas assets in Montana. The bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. Proceeds were used to redeem our 6.04%, $150 million of Montana First Mortgage Bonds due 2016 and finance incremental Montana capital expenditures.

As of December 31, 2015, 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. 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 $1.8 million in 2016, $2.0 million in 2017, $57.1 million in 2018, $252.3 million in 2019 and $2.5 million in 2020.

(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,	
	2015	2014
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 468	$ 327
Risk Partners Assurance, Ltd.	18	18
	$ 486	**$ 345**
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	$ 1,526	$ 1,466

(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 accelerated tax depreciation deductions (including bonus depreciation when applicable) 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 due to the lapse of statutes of limitation in the third quarter of 2014. In addition, in the third quarter of 2014, we elected the safe harbor method related to the deductibility of repair costs. This resulted in 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 adjustments.

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,	
	2015	2014
Pension / postretirement benefits	$ 54,440	$ 51,817
Unbilled revenue	28,390	19,863
Property taxes	24,648	879
Compensation accruals	17,441	17,315
Customer advances	14,197	11,817
AMT credit carryforward	13,143	10,357
Environmental liability	9,410	8,968
Production tax credit	6,550	6,452
Interest rate hedges	6,483	6,251
NOL carryforward	18,244	42,787
Regulatory liabilities	2,862	975
QF obligations	1,098	2,162
Reserves and accruals	1,820	2,102
Other, net	2,571	4,442
Deferred Tax Asset	**201,297**	**186,187**
Excess tax depreciation	(396,068)	(351,823)
Goodwill amortization	(178,084)	(137,090)
Flow through depreciation	(125,441)	(103,677)
Regulatory assets	(14,901)	(21,394)
Reserves and accruals	(6,406)	(330)
Deferred Tax Liability	**(720,900)**	**(614,314)**
Deferred Tax Liability, net	**$ (519,603)**	**$ (428,127)**

At December 31, 2015 we estimate our total federal NOL carryforward to be approximately $215.7 million prior to consideration of unrecognized tax benefits. If unused, our federal NOL carryforwards will expire as follows: $1.6 million in 2029; $127.5 million in 2031; $13.3 million in 2033 and $73.3 million in 2034. We estimate our state NOL carryforward as of December 31, 2015 is approximately $154.1 million. If unused, our state NOL carryforwards will expire as follows: $85.3 million in 2018; $10.5 million in 2020 and $58.3 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):

		2015		2014
Unrecognized Tax Benefits at January 1	$	95,929	$	113,466
Gross increases - tax positions in prior period		44		—
Gross decreases - tax positions in prior period		(2,903)		—
Gross increases - tax positions in current period		494		909
Gross decreases - tax positions in current period		(1,177)		(5,597)
Lapse of statute of limitations		—		(12,849)
Unrecognized Tax Benefits at December 31	$	92,387	$	95,929

Our unrecognized tax benefits include approximately $65.2 million and $62.4 million related to tax positions as of December 31, 2015 and 2014, 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. During the year ended December 31, 2015, we did not recognize expense for interest and penalties in the Statements of Income and did not have any amounts accrued in the Balance Sheets. During the year ended December 31, 2014, we released approximately $0.4 million of interest in the Statements of Income. As of December 31, 2014, we did not have any amounts 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,					
	2015			2014		
	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount
Foreign currency translation adjustment	$ 558	$ —	$ 558	$ 265	—	$ 265
Reclassification of net gains on derivative instruments	(1,125)	427	(698)	(1,110)	426	(684)
Realized loss on cash flow hedging derivatives	—	—	—	(18,388)	7,243	(11,145)
Pension and postretirement medical liability adjustment	504	(194)	310	134	(52)	82
Other comprehensive income (loss)	$ (63)	$ 233	$ 170	$ (19,099)	$ 7,617	$ (11,482)

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

	December 31, 2015	December 31, 2014
Foreign currency translation	$ 1,355	$ 797
Derivative instruments designated as cash flow hedges	(9,014)	(8,316)
Pension and postretirement medical plans	(937)	(1,247)
Accumulated other comprehensive income	(8,596)	(8,766)

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

		December 31, 2015			
		Year 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		$ (8,316)	$ (1,247)	$ 797	$ (8,766)
Other comprehensive income before reclassifications		—	—	558	$ 558
Amounts reclassified from accumulated other comprehensive income	Interest on long-term debt	(698)	—	—	$ (698)
Amounts reclassified from accumulated other comprehensive income		—	310	—	$ 310
Net current-period other comprehensive (loss) income		(698)	310	558	170
Ending Balance		$ (9,014)	$ (937)	$ 1,355	$ (8,596)

	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
		December 31, 2014			
		Year Ended			
Beginning balance		$ 3,513	$ (1,329)	$ 532	$ 2,716
Other comprehensive income (loss) before reclassifications		(11,145)	—	265	$ (10,880)
Amounts reclassified from accumulated other comprehensive income	Interest on long-term debt	(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)

(17) 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,	
	2015	2014	2015	2014
Change in benefit obligation:				
Obligation at beginning of period	$ 688,444	$ 567,866	$ 30,004	$ 30,084
Service cost	12,362	10,830	526	465
Interest cost	26,174	26,147	786	859
Plan amendments	—	—	1,045	—
Actuarial (gain) loss	(47,351)	107,023	(616)	958
Settlements	—	—	390	690
Benefits paid	(50,746)	(23,422)	(3,483)	(3,052)
Benefit Obligation at End of Period	$ 628,883	$ 688,444	$ 28,652	$ 30,004
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 556,051	$ 516,352	$ 18,040	$ 18,183
Return on plan assets	(15,461)	52,921	—	1,391
Employer contributions	10,200	10,200	3,415	1,518
Benefits paid	(50,746)	(23,422)	(3,483)	(3,052)
Fair value of plan assets at end of period	$ 500,044	$ 556,051	$ 17,972	$ 18,040
Funded Status	$ (128,839)	$ (132,393)	$ (10,680)	$ (11,964)
Amounts Recognized in the Balance Sheet Consist of:				
Current liability	—	—	(2,584)	(1,169)
Noncurrent liability	(128,839)	(132,393)	(8,096)	(10,795)
Net amount recognized	$ (128,839)	$ (132,393)	$ (10,680)	$ (11,964)
Amounts Recognized in Regulatory Assets Consist of:				
Prior service (cost) credit	(255)	(502)	14,021	17,098
Net actuarial loss	(142,305)	(153,268)	(5,219)	(4,945)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(1,000)	(1,151)
Net actuarial gain	—	—	(102)	(409)
Total	$ (142,560)	$ (153,770)	$ 7,700	$ 10,593

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,	
	2015	2014
Projected benefit obligation	$ 628.9	$ 688.4
Accumulated benefit obligation	626.0	685.0
Fair value of plan assets	500.0	556.1

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 Pension Benefits	
	December 31,		December 31,	
	2015	2014	2015	2014
Components of Net Periodic Benefit Cost				
Service cost	$ 12,362	10,830	$ 526	$ 465
Interest cost	26,174	26,147	786	859
Expected return on plan assets	(31,561)	(29,506)	(969)	(981)
Amortization of prior service cost (credit)	246	246	(1,882)	(1,998)
Recognized actuarial loss	10,634	2,118	385	348
Settlement loss recognized	—	—	390	690
Net Periodic Benefit Cost (Credit)	$ 17,855	9,835	$ (764)	$ (617)

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 2016 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service credit (cost)	$ (246)	$ 1,882
Accumulated loss	(9,864)	(349)

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2015 and 2014. 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 2015 and 2014, we set the discount rate using a yield curve analysis, which 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 2016.

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2015	2014	2015	2014
Discount rate	4.15-4.30 %	3.75-3.90 %	3.60-3.75 %	3.20-3.40 %
Expected rate of return on assets	5.80	5.80	5.80	5.80
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 increase by 7.94% in 2016 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease to an ultimate trend of 4.5% by the year 2038. 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,	
	2015	2014	2015	2014
Domestic debt securities	55.0%	55.0%	40.0%	40.0%
International debt securities	5.0	5.0	—	—
Domestic equity securities	34.0	34.0	50.0	50.0
International equity securities	6.0	6.0	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,	
	2015	2014	2015	2014	2015	2014
Cash and cash equivalents	0.4%	—%	—%	0.1%	0.1%	0.2%
Domestic debt securities	54.9	56.0	65.8	65.6	37.0	37.2
International debt securities	4.7	4.4	4.5	4.5	—	—
Domestic equity securities	33.9	34.1	24.9	25.1	54.2	53.9
International equity securities	6.1	5.5	4.8	4.7	8.7	8.7
	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.

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 2016 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 2015, 2014 and 2013 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2015	2014
NorthWestern Energy Pension Plan (MT)	$ 9,000	$ 9,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 10,200	$ 10,200

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

	Pension Benefits	Other Postretirement Benefits
2016	$ 29,439	$ 3,623
2017	30,600	3,407
2018	32,173	3,265
2019	33,536	3,057
2020	34,738	2,943
2021-2025	192,419	10,785

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, 2015 and 2014 were $9.5 million and $8.7 million.

(18) 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, 2015, there were 933,387 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 Unit Awards

Performance unit awards are granted annually under the ECP. These awards vest at the end of the three-year performance period if 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 unit awards which were granted in 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 and 2015, 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 unit 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:

	2015	2014
Risk-free interest rate	1.06%	0.67%
Expected life, in years	3	3
Expected volatility	14.2% to 19.0%	15.5% to 23.3%
Dividend yield	3.5%	3.3%

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, 2015, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	180,572	$ 35.77
Granted	93,437	42.47
Vested	(85,966)	32.97
Forfeited	(471)	36.13
Remaining nonvested grants	187,572	$ 40.39

We recognized compensation expense of $4.4 million and $3.1 million for the years ended December 31, 2015 and 2014, respectively, and a related income tax (expense) benefit of $(1.8) million and $0.1 million for the years ended December 31, 2015 and 2014, respectively. As of December 31, 2015, we had $4.5 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 $2.8 million and $2.1 million for the years ended December 31, 2015 and 2014, 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, 2015, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	41,720	$ 35.14
Granted	15,593	44.77
Vested	—	—
Forfeited	—	—
Remaining nonvested grants	57,313	$ 37.76

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, 2015 and 2014, DSUs issued to members of our Board totaled 35,030 and 26,460, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2015 and 2014 was approximately $1.3 million and $2.3 million, respectively.

(19) 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 18 - Stock-Based Compensation.

Beethoven Issuance - During October 2015, we issued 1,100,000 shares of our common stock at $51.81 per share, for aggregate net proceeds of $57 million to finance a portion of the Beethoven wind project.

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 39,504 and 23,630 during the years ended December 31, 2015 and 2014, 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.

(20) 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 $955.3 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $740.6 million through 2029. The present value of the remaining QF liability is recorded in our Balance Sheets as an accumulated miscellaneous operating provisions. The following summarizes the change in the QF liability (in thousands):

	December 31, 2015	December 31, 2014
Beginning QF liability	$ 136,893	$ 136,448
Unrecovered amount	(9,379)	(10,128)
Interest on long-term debt	10,796	10,573
Ending QF liability	$ 138,310	$ 136,893

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

	Gross Obligation	Recoverable Amounts	Net
2016	72,629	57,188	15,441
2017	74,684	57,789	16,895
2018	76,782	58,401	18,381
2019	78,918	59,020	19,898
2020	81,068	59,647	21,421
Thereafter	571,212	448,547	122,665
Total	$ 955,293	$ 740,592	$ 214,701

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 26 years. Costs incurred under these contracts are included in operating expenses in the Income Statement and were approximately $241.6 million and $402.3 million for the years ended December 31, 2015 and 2014, respectively. As of December 31, 2015, our commitments under these contracts are $226.1 million in 2016, $189.9 million in 2017, $147.1 million in 2018, $143.3 million in 2019, $109.0 million in 2020, and $1.1 billion 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 $24.1 million between 2016 and 2040. These commitments are not reflected in our Financial Statements.

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 and is estimated to range between $27 million to $32 million. As of December 31, 2015, we have a reserve of approximately $31.5 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. 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.

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. During the second quarter of 2015, we reached a settlement agreement with an insurance carrier for the former Montana Power Company for what were primarily generation related environmental remediation costs. As a result of this settlement, we recognized a net recovery of approximately $20.8 million. The environmental remediation costs were never reflected in customer rates and the litigation expenses have not been treated as utility expenses. In a 2002 order approving NorthWestern's acquisition of the transmission and distribution assets of the Montana Power Company, the MPSC approved a stipulation in which NorthWestern agreed to release its customers from all environmental liabilities associated with the Montana Power Company's generation assets.

Manufactured Gas Plants - Approximately $23.4 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 $11.5 million, and we estimate that approximately $6.8 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. 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. Soil and coal tar were removed at the sites in accordance with MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. An investigation conducted at the Missoula site did not require remediation activities, but required preparation of a groundwater monitoring plan. Monitoring wells have been installed and groundwater is monitored semiannually. At the request of Missoula Valley Water Quality District, a draft risk assessment was prepared for the Missoula site and presented to the Missoula County Water Quality Board (MCWQB). The MCWQB deferred all decision making to the MDEQ, but suggested additional site delineation. Additional delineation work began in December 2015 and will be continued in 2016. The result of the additional delineation work may lead to amending the risk assessment and / or development of a remedial alternatives report followed by implementation of a remedy. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action at these sites 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 (CO2). 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 coal-fired electric generating plants, all of which are operated by other companies. We 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 new and existing sources of GHG emissions.

On August 3, 2015, the EPA released for publication in the Federal Register, the final standards of performance to limit GHG emissions from new, modified and reconstructed fossil fuel generating units and from newly constructed and reconstructed stationary combustion turbines. The standards reflect the degree of emission limitations achievable through the application of the best system of emission reduction that the EPA determined has been demonstrated for each type of unit.

In a separate action that also affects power plants, on August 3, 2015, the EPA released its final rule establishing GHG performance standards for existing power plants under Clean Air Act Section 111(d). EPA refers to this rule as the Clean Power Plan or CPP. The CPP specifically establishes CO_2 emission performance standards for existing electric utility steam generating units and stationary combustion turbines. States may develop implementation plans for affected units to meet the individual state targets established in the CPP or may adopt a federal plan. The EPA has given states the option to develop compliance plans for annual rate-based reductions (pounds per megawatt hour (MWH)) or mass-based tonnage limits for CO_2. The 2030 rate-based requirement for all existing affected generating units in Montana and South Dakota is 1,305 and 1,167 pounds per MWH, respectively. The rate-based approach requires a 38.4 percent reduction in South Dakota and a 47.4 percent reduction in Montana from 2012 levels by 2030. The mass-based approach for existing units in South Dakota requires a 30.9 percent decrease by 2030, while in Montana the mass-based approach requires a 41.0 percent decrease by 2030. States are required to submit initial plans for achieving GHG emission standards to EPA by September 2016, but may seek additional time to finalize State plans by September 2018. The initial performance period for compliance would commence in 2022, with full implementation by 2030. The EPA also indicated that states may establish emission trading programs to facilitate compliance with the CPP and provides three options: an emission rate trading program, which would allow the trading of emission reduction credits equal to one MWH of emission free generation; a mass-based program, which would allow trading of allowances with an allowance equal to one short ton of CO_2; and a state measures program, that would allow intra-state trading to achieve the state-wide average emission rate.

On August 3, 2015, EPA also proposed a federal plan that would be imposed if a state fails to submit a satisfactory plan under the CPP. The federal plan proposal includes a "model trading rule" that describes how the EPA would establish an emission trading program as part of the federal plan to allow affected units to comply with the emission rate requirements. EPA proposed both an emission rate trading plan and a mass-based trading plan and indicated that the final federal rule will elect one of the two options. Comments on the proposed federal plan and model trading rule were due January 21, 2016. The EPA has indicated that it intends to finalize both the federal plan and the model trading rules in the summer of 2016.

The CPP reduction of 47 percent in carbon dioxide emissions in Montana by 2030 is the greatest reduction target among the lower 48 states, according to a nationwide analysis. Our Montana generation portfolio emits less carbon on average than the EPA's 2030 target due to investments we made prior to 2013 in carbon-free generation resources. However, the CPP's target reduction is applied on a statewide basis, and investments made prior to 2012 are not counted in the CPP's 2030 target. The State of Montana is required by the CPP to submit a satisfactory state plan to EPA by no later than September 2018. The state plan will determine whether we will have to meet rate-based or mass-based requirements and, if the state adopts a mass-based plan, the number and vintages of allowances that will be allocated to Colstrip. Until the plan is submitted, or a federal plan is imposed, we cannot predict the impact of the CPP on us. We asked the University of Montana's Bureau of Business and Economic Research (BBER) to study the potential impacts of the CPP across Montana. The BBER study looked at the implications of closing the Colstrip generating facilities in southeast Montana as a scenario for complying with the federal rule. The study's conclusions describe the likely loss of jobs and population, the decline in the local and state tax base, the impact on businesses statewide, and the closure's impact on electric reliability and affordability. The electricity produced at Unit 4 represents approximately 25 percent of our customer needs. Closing Colstrip would lead to higher utility rates in order to replace the base-load generation that currently is provided by Colstrip. Closing Colstrip would also create significant issues with the transmission grid that serves Montana, and we would lose transmission revenues that are credited to and lower electric customer bills.

On October 23, 2015, the same date the CPP was published in the Federal Register, we along with other utilities, trade groups, coal producers, labor and business organizations, filed Petitions for Review of the CPP with the United States Court of Appeals for the District of Columbia Circuit. Accompanying these Petitions for Review were Motions to Stay the implementation of the CPP. On January 21, 2016, the U.S. Court of Appeals for the District of Columbia denied the requests for stay but ordered expedited briefing on the merits, with oral argument scheduled for June 2, 2016. On January 26, 2016, 29 states and state agencies asked the U.S. Supreme Court to issue an immediate stay of the CPP. On January 27, 2016, 60 utilities and allied petitioners also requested the U.S. Supreme Court to immediately stay the CPP, and we are among the utilities seeking a stay. On February 9, 2016, the U.S. Supreme Court entered an order staying the Clean Power Plan. The stay of the CPP will remain in place until the U.S. Supreme Court either denies a petition for certiorari following the U.S. Court of Appeals' decision on the substantive challenges to the CPP, if one is submitted, or until the U.S. Supreme Court enters judgment following grant of a petition for certiorari. The effect is to delay the CPP's deadlines until challenges to the CPP has been fully litigated and the U.S. Supreme Court has ruled. We do not expect a final judicial decision on challenges to the CPP until mid-2017 at the earliest, and, more likely, early 2018.

On December 22, 2015 we also filed an administrative Petition for Reconsideration with the EPA, requesting it reconsider the CPP, on the grounds that the CO_2 reductions in the CPP were substantially greater in Montana than in the proposed rule. We also requested EPA stay the CPP while it considered our Petition for Reconsideration. At this time no action has been taken on the Petition for Reconsideration or stay request.

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 prevention of significant deterioration program, which includes most electric generating units.

Requirements to reduce GHG emissions from stationary sources could cause us to incur material costs of compliance, increase our costs of procuring electricity, decrease transmission revenue and impact cost recovery. Although there continues to be proposed 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 are evaluating the implications of these rules and technology available to achieve the CO_2 emission performance standards. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from the final rules that, in our view, disproportionately impact customers in our region, and to seek relief from the final compliance requirements. We cannot predict the ultimate outcome of these matters nor what our obligations might be under the state compliance plans with any degree of certainty until they are finalized; however, complying with the carbon emission standards, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of our jointly owned facilities or for individual owners to participate in their proportionate ownership of the coal-fired generating units. This could lead to significant impacts to customer rates for recovery of plant improvements and / or closure related costs and costs to procure replacement power. In addition, these changes could impact system reliability due to changes in generation sources.

Coal Combustion Residuals - The EPA's final rule regulating CCRs became effective on October 14, 2015. The rule imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plants and not closed. Under the rule, the EPA regulates CCRs as non-hazardous under the Resource Conservation and Recovery Act Subtitle B and allows beneficial use of CCRs, with some restrictions. The rule's requirements for covered CCR impoundments and landfills include commencement or completion of closure activities generally between three and ten years from certain triggering events. Based on our assessment of these requirements, we recorded an increase to our existing AROs of approximately $12.0 million during the second quarter of 2015. AROs represent the anticipated costs of removing assets upon retirement and are provided for over the life of those assets as a component of depreciation expense. Our depreciation method, including cost of removal, is established by the respective regulatory commissions. All costs of the rule are expected to be recovered from customers in future rates. Therefore, consistent with this regulated treatment, we reflect this increase to the accrual of removal costs by increasing our asset retirement obligations. Further, we do not have any assets that are legally restricted related to the settlement of CCR related asset retirement obligations.

The actual asset retirement costs related to the CCR Rule requirements may vary substantially from the estimates used to record the increased obligation due to uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. We will coordinate with the plant operators and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, we will update the ARO obligation for these changes in estimates, which could be material.

Legislation has been introduced in Congress to permanently designate coal ash as non-hazardous and establish a national system to regulate coal ash disposal, but leave enforcement largely to states. We cannot predict at this time the final outcome of any such legislation and what impact, if any, it 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, which became effective in October 2014, gives options for meeting BTA, and provides a flexible compliance approach. 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 filed by industry and environmental groups are under review in the Court of Appeals.

In November 2015, the EPA published final regulations on effluent limitations for power plant wastewater discharges, including mercury, arsenic, lead and selenium. The rule became effective in January 2016. Some of the new requirements for existing power plants would be phased in starting in 2018 with full implementation of the rule by 2023. The EPA rule estimates that 12 percent of the steam electric power plants in the U.S. will have to make new investments to meet the requirements of the new effluent limitation regulations; 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 in which 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. The rule was challenged by industry groups and states, and was upheld by the D.C. Circuit Court in April 2014. The decision was appealed to the Supreme Court and in June 2015, the Supreme Court issued an opinion that the EPA did not properly consider the costs to industry when making the requisite "appropriate and necessary" determination as part of its analysis in connection with the issuance of the MATS rule. The Supreme Court remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit, and on July 31 the litigation was formally sent back to the D.C. Circuit, which will decide whether the standards will be vacated or will remain in place while the EPA addresses the Supreme Court decision. The EPA indicated that it will seek a remand without vacatur of the MATS rule, and in support of that request, the EPA will submit to the court a declaration establishing a plan to "complete the required consideration of costs" to support the "appropriate and necessary finding" by spring 2016. Installation or upgrading of relevant environmental controls at our affected plants is complete. Colstrip Unit 4 is currently controlling emissions of mercury under regulations issued by the State of Montana, which are stricter than the Federal MATS. At this time, we cannot predict whether and when compliance with the MATS rule ultimately will be required.

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to reduce emissions from electric generating units that interfere with the ability of downwind states to achieve ambient air quality standards. Under CSAPR, significant reductions in emissions of nitrogen oxide (NOx) and sulfur dioxide (SO2) were to be required in certain states beginning in 2012. 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. In December, 2015 EPA published a proposed update to the CSAPR rule. Litigation of the remaining CSAPR lawsuits is pending.

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 Units 3 and 4 do 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 challenged the EPA's decision not to require any emissions reductions from Colstrip Units 3 and 4. In June 2015, the U.S. Court of Appeals for the Ninth Circuit rejected the challengers' contention that the EPA should have required additional pollution-reduction technologies on Unit 4 beyond those in the regulations and the matter is back in EPA Region 8 for action.

Jointly Owned Plants - We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa and Montana that are or may become subject to the various regulations discussed above that have been issued or proposed.

South Dakota. The South Dakota DENR determined that the Big Stone plant, in 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 installed a new BART compliant air quality control system (AQCS) to reduce SO_2, NOx and particulate emissions. The project was substantially completed and placed in service in December 2015. We capitalized costs of approximately $98 million (including allowance for funds used during construction).

North Dakota. The North Dakota Regional Haze SIP requires the Coyote generating facility, in which we have 10.0% ownership, to reduce its NOx emissions by July 2018. Coyote is in the process of installing 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, with the project expected to be operational by the third quarter of 2016. The cost of the control equipment is not significant.

Iowa. The Neal #4 generating facility, in which we have an 8.7% ownership, completed the installation of a scrubber, baghouse, activated carbon injection and a selective non-catalytic reduction system in 2013 to comply with national ambient air quality standards and the MATS.

Montana. Colstrip Unit 4, a coal fired generating facility in which we have a 30% interest, is subject to EPA's CCR Rule. A compliance plan has been developed and is in the initial stages of implementation. The current estimate of the total project cost is approximately $90.0 million (our share is 30%) over the remaining life of the facility.

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 SO2, NOx 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. 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 United States Magistrate Judge (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 Court, 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 alleged 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. The parties filed motions for summary judgment and briefs in support with regard to issues affecting the remaining claims.

On December 1, 2015, the Court held oral argument on all pending motions for summary judgment, and on December 31, 2015, the Magistrate issued findings and recommendations which (a) denied Plaintiffs' motion for partial summary judgment regarding routine maintenance, repair and replacement; (b) denied Plaintiffs' motion for partial summary judgment that the redesign projects for the Unit 1 and 4 turbines and the Unit 1 economizer were not "like kind replacements"; (c) granted Defendants' motion for partial summary judgment regarding Plaintiffs' use of the "actual-to-potential" emissions test; (d) granted in part and denied in part Plaintiffs' motion for partial summary judgment regarding the allowable period from which to select a baseline for the Unit 3 reheater project; (e) granted in part and denied in part Defendants' motion for partial summary judgment on baseline selection; and (f) granted Defendants' motion for partial summary judgment on emissions calculations for alleged aggregated turbine and safety valve project. Plaintiffs filed objections to the Magistrate's findings and recommendations on January 19, 2016, and Defendants filed their response on February 5, 2016. The Court's ruling on these motions, when issued, should clarify what claims remain and the standards to be applied at trial. A bench trial is scheduled for May 31, 2016.

We intend to vigorously defend this 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, Montana Refinery Outage Claim

In August 2014, we received a letter from the ExxonMobil refinery in Billings claiming that it had sustained damages of approximately $48.5 million as a result of a January 2014 electrical outage. In December 2015, Exxon increased the estimated losses related to that incident to approximately $61.7 million. On January 13, 2016, a second electrical outage shut down the ExxonMobil refinery. On January 22, 2016, ExxonMobil filed suit against NorthWestern in U.S. District Court in Billings, Montana, seeking unspecified compensatory and punitive damages arising from both outages. We dispute ExxonMobil's claims and intend to vigorously defend this lawsuit. We have reported the refinery's claims and lawsuit to our liability insurance carriers under our liability insurance coverage, which has a $2.0 million per occurrence retention. This matter is in the initial stages and we cannot predict an outcome or estimate the amount or range of loss that would be associated with an adverse result.

State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana filed a complaint on remand with the Montana First Judicial District Court (District Court), naming us, along with Talen Montana, LLC (Talen), as defendants. The State claims it owns the riverbeds underlying 10 of our hydroelectric facilities (dams, along with reservoirs and tailraces) on the Missouri, Madison and Clark Fork Rivers, and seeks rents for Talen's and our use and occupancy of such lands. The facilities at issue in the litigation include the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan and Morony facilities on the Missouri-Madison Rivers and the Thompson Falls facility on the Clark Fork River. We acquired these facilities from Talen in November 2014.

Prior to our acquisition of the facilities, Talen litigated this issue against the State in Montana state courts and in the United States Supreme Court. In August 2007, the District Court determined that the 10 hydroelectric facilities were located on rivers which were navigable and that the State held title to the riverbeds. Subsequently, in June 2008, the District Court awarded the State compensation with respect to all 10 facilities of approximately $34 million for the 2000-2006 period and approximately $6 million for 2007 (we have owned the facilities since November 2014). The District Court deferred the determination of compensation for 2008 and future years to the Montana State Land Board.

Talen appealed the issue of navigability to the Montana Supreme Court, which in March 2010 affirmed the District Court decision. In June 2011, Talen petitioned the United States Supreme Court to review the Montana Supreme Court decision. The United States Supreme Court issued an opinion in February 2012, overturning the Montana Supreme Court and holding that the Montana courts erred first by not considering the navigability of the rivers on a segment-by-segment basis and second in relying on present day recreational use of the rivers. The United States Supreme Court also considered the navigability of what it referred to as the Great

Falls Reach and concluded, at least from the head of the first waterfall to the foot of the last, that the Great Falls Reach was not navigable for title purposes, and thus the State did not own the riverbeds in that segment. The United States Supreme Court remanded the case to the Montana Supreme Court for further proceedings not inconsistent with its opinion.

Following the 2012 remand, the case laid dormant for four years until the State filed the complaint on remand with the District Court. The complaint on remand renews all of the State's claims that the rivers on which the 10 hydroelectric facilities are located are navigable (including the Great Falls Reach), and that because they were navigable the riverbeds became State lands upon Montana's statehood in 1889 and that the State is entitled to rent for their use. The State's complaint on remand does not claim any specific rental amount. Pursuant to the terms of our acquisition of the hydroelectric facilities, Talen and NorthWestern will share jointly the expense of this litigation, and Talen is responsible for any rents applicable to the periods of time prior to the acquisition (i.e., before November 18, 2014), while we are responsible for periods thereafter.

We dispute the State's claims and intend to vigorously defend the lawsuit. This matter is in the initial stages, and we cannot predict an outcome. If on remand the District Court determines the riverbeds under all 10 of the hydroelectric facilities are navigable (including the five hydroelectric facilities on the Great Falls Reach) and if it calculates damages as before remand, we estimate the annual rents could be approximately $7.0 million commencing in November 2014, when we acquired the facilities. We anticipate that any obligation to pay the State rent for use and occupancy of the riverbeds would be recoverable in rates from customers, although there can be no assurances that the MPSC would approve any such recovery.

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	**Intangible Plant**					
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	7,867,240	-	7,867,240	7,394,194	6.40%
6	**Total Intangible Plant**	7,889,239	-	7,889,239	7,416,193	6.38%
7						
8	**Production Plant**					
9						
10	**Steam Production**					
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	418,387,731	-	418,387,731	416,717,131	0.40%
18	**Total Steam Production Plant**	418,387,731	-	418,387,731	416,717,131	0.40%
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable	-	-	-	-	-
22	**Total Nuclear Production Plant**	-	-	-	-	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	5,732,621	-	5,732,621	5,787,621	-0.95%
26	331 Structures and Improvements	123,121,353	-	123,121,353	123,105,566	0.01%
27	332 Reservoirs, Dams and Waterways	156,194,390	-	156,194,390	132,384,175	17.99%
28	333 Water Wheel, Turbine, Generators	117,996,686	-	117,996,686	104,216,181	13.22%
29	334 Accessory Electric Equipment	82,641,997	-	82,641,997	78,135,731	5.77%
30	335 Misc. Power Plant Equipment	36,525,062	-	36,525,062	36,525,062	0.00%
31	336 Roads, Railroads and Bridges	2,453,164	-	2,453,164	2,349,226	4.42%
32	**Total Hydraulic Production Plant**	524,665,273	-	524,665,273	482,503,562	8.74%
33						
34	**Other Production**					
35	340 Land and Land Rights	160,028	-	160,028	160,028	0.00%
36	341 Structures and Improvements	28,970,681	19,232	28,951,449	28,935,794	0.05%
37	342 Fuel Holders & Accessories	12,432,138	112,084	12,320,054	12,320,053	0.00%
38	343 Prime Movers	-	-	-		-
39	344 Generators	49,219,313	2,247,016	46,972,297	44,554,641	5.43%
40	345 Accessory Electric Equipment	6,884,726	524,241	6,360,485	6,360,485	0.00%
41	346 Misc. Power Plant Equipment	166,487,173	7,268	166,479,905	164,827,056	1.00%
42	**Total Other Production Plant**	264,154,059	2,909,841	261,244,218	257,158,057	1.59%
43	**Total Production Plant**	1,207,207,063	2,909,841	1,204,297,222	1,156,378,750	4.14%

Sch. 19 cont.	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	**Transmission Plant**					
3	350 Land and Land Rights	31,748,133	-	31,748,133	27,842,575	14.03%
4	352 Structures and Improvements	28,152,892	-	28,152,892	26,498,470	6.24%
5	353 Station Equipment	229,365,599	-	229,365,599	202,020,602	13.54%
6	354 Towers and Fixtures	28,732,521	-	28,732,521	28,732,934	0.00%
7	355 Poles and Fixtures	209,772,118	913,165	208,858,953	180,991,824	15.40%
8	356 Overhead Conductors & Devices	147,105,921	716,080	146,389,841	141,871,767	3.18%
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	**Total Transmission Plant**	678,945,238	2,330,473	676,614,765	611,324,998	10.68%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	5,298,442	601	5,297,841	5,409,383	-2.06%
16	361 Structures and Improvements	12,845,864	1,203,991	11,641,873	9,483,938	22.75%
17	362 Station Equipment	162,553,407	4,175,855	158,377,552	146,180,009	8.34%
18	363 Storage Battery Equipment	-	-	-	-	-
19	364 Poles, Towers, and Fixtures	245,449,014	412,071	245,036,943	222,110,721	10.32%
20	365 Overhead Conductors & Devices	110,769,859	495,865	110,273,994	105,938,448	4.09%
21	366 Underground Conduit	89,723,255	449,108	89,274,147	79,476,997	12.33%
22	367 Undergrnd Conductors & Devices	161,929,586	2,917,734	159,011,852	141,820,070	12.12%
23	368 Line Transformers	197,767,452	903,314	196,864,138	192,933,603	2.04%
24	369 Services	110,681,299	255,569	110,425,730	104,326,650	5.85%
25	370 Meters	52,923,760	96,955	52,826,805	52,344,570	0.92%
26	371 Installations on Cust. Premises	-	-	-	-	-
27	372 Leased Property on Cust. Premises	-	-	-	-	-
28	373 Street Lighting and Signal Systems	53,617,717	19,872	53,597,845	53,021,681	1.09%
29	**Total Distribution Plant**	1,203,559,655	10,930,935	1,192,628,720	1,113,046,070	7.15%
30						
31	**General Plant**					
32	389 Land and Land Rights	721,526	-	721,526	616,736	16.99%
33	390 Structures and Improvements	9,000,003	506,969	8,493,034	8,443,797	0.58%
34	391 Office Furniture and Equipment	3,153,387	-	3,153,387	2,677,643	17.77%
35	392 Transportation Equipment	44,949,043	244,517	44,704,526	41,509,201	7.70%
36	393 Stores Equipment	648,536	-	648,536	569,515	13.88%
37	394 Tools, Shop & Garage Equipment	7,169,760	7,497	7,162,263	6,433,388	11.33%
38	395 Laboratory Equipment	1,876,484	2,594	1,873,890	2,145,689	-12.67%
39	396 Power Operated Equipment	3,876,088	-	3,876,088	3,419,233	13.36%
40	397 Communication Equipment	20,032,725	2,038,244	17,994,481	16,425,127	9.55%
41	398 Miscellaneous Equipment	2,031,079	-	2,031,079	1,995,260	1.80%
42	399 Other Tangible Equipment	-	-	-	-	-
43	**Total General Plant**	93,458,631	2,799,821	90,658,810	84,235,589	7.63%
44	**Total Plant in Service**	3,191,059,826	18,971,070	3,172,088,756	2,972,401,600	6.72%
45						
46	4101 El Plant Allocated from Common	79,134,221	-	79,134,221	60,384,311	31.05%
47	103 Experimental Electric Plant Unclassified	658,807	-	658,807		
48	105 El Plant Held for Future Use	3,778,101	-	3,778,101	3,553,513	(0.97)
49	107 El Construction Work in Progress	51,828,880	162,038	51,666,842	117,146,542	-
50						
51						
52	TOTAL ELECTRIC PLANT	$ 3,326,459,834	$ 19,133,108	$ 3,307,326,726	$ 3,153,485,966	-

Sch. 19 cont.	MONTANA PLANT IN SERVICE - ELECTRIC		
	CONSOLIDATED PLANT IN SERVICE	December 31, 2015	December 31, 2014
1			
2	Montana Electric	$ 3,172,088,756	$ 2,972,401,600
3	Yellowstone National Park	18,971,070	16,629,416
4	Montana Natural Gas (Includes CMP)	728,443,945	699,769,408
5	Common	121,487,443	93,665,529
6	Townsend Propane	1,519,564	1,519,564
7	South Dakota Electric	836,490,812	597,960,820
8	South Dakota Natural Gas	170,070,949	163,980,215
9	South Dakota Common	54,801,857	49,516,491
10	Asset Retirement Obligation	29,338,772	16,678,342
11	**TOTAL PLANT**	$ 5,133,213,168	$ 4,612,121,385

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	$ 416,264,497	$ 66,915,837	$ -	$ 66,915,837	$ 61,469,060	2.94%
4							
5	Nuclear Production	-	-	-	-	-	-
6							
7	Hydraulic Production	476,715,941	10,109,244	-	10,109,244	1,191,779	2.00%
8							
9	Other Production	257,088,029	41,539,367	2,677,364	38,862,003	29,733,220	3.55%
10							
11	Transmission	603,899,405	309,624,430	2,001,951	307,622,479	292,772,101	2.80%
12							
13	Distribution	1,109,878,850	591,465,881	4,750,040	586,715,841	566,710,557	3.15%
14							
15	General and Intangible	91,651,781	54,350,594	340,288	54,010,306	48,196,672	8.78%
16							
17	Common	58,276,555	23,096,567	-	23,096,567	21,997,266	6.25%
18							
19							
20	**Total Accum Depreciation**	$ 3,013,775,058	$ 1,097,101,920	$ 9,769,643	$ 1,087,332,277	$ 1,022,070,655	3.00%
21							
22							
23							

24	**Consolidated**	December 31,	
25	**Accumulated Depreciation**	2015	2014
26			
27	Montana Electric	$1,064,235,710	$1,000,073,389
28	Yellowstone National Park	9,769,643	9,582,851
29	Montana Natural Gas (Includes CMP)	285,051,237	267,809,946
30	Common	36,076,855	34,643,025
31	Townsend Propane	810,882	769,983
32	South Dakota Electric	270,409,898	268,707,554
33	South Dakota Natural Gas	80,514,996	75,774,427
34	South Dakota Common	15,759,748	15,531,797
35	Acquisition Writedown	56,799,088	59,503,576
36	Basin Creek Capital Lease	19,099,502	17,089,022
37	FIN 47	2,653,230	2,092,675
38	CWIP-Capital Retirement Clearing	-9,313,858	-6,556,494
39	**Total Consolidated Accum Depreciation**	$1,831,866,931	$1,745,021,750

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
2	151 Fuel Stock	$2,087,098	$ -	$2,087,098	$2,208,383	-5.49%
4	154 Plant Materials & Operating Supplies					
5	Assigned and Allocated to:					
6	Operation & Maintenance	-		-	-	-
7	Construction	-		-	-	-
8	Production Plant	4,766,379		4,766,379	4,383,990	8.72%
9	Transmission Plant	3,292,126		3,292,126	3,016,669	9.13%
10	Distribution Plant	11,356,226		11,356,226	10,815,991	4.99%
13	**Total MT Materials and Supplies**	$21,501,829	$ -	$21,501,829	$ 20,425,033	5.27%

	Consolidated Fuel Stock	December 31, 2015	December 31, 2014
19	Montana Electric	$2,087,098	$2,208,383
20	South Dakota	6,153,775	5,421,968
22	**Total Fuel Stock**	$8,240,873	$7,630,351

	Consolidated Materials and Supplies	December 31, 2015	December 31, 2014
29	Montana Electric	$19,414,731	$18,216,650
30	Montana Natural Gas	3,201,368	3,019,370
31	South Dakota	7,756,577	7,846,464
33	**Total Consolidated Materials and Supplies**	$30,372,676	$29,082,484

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC				
	Commission Accepted - Most Recent		% Capital Structure	% Cost Rate	Weighted Cost
	Regulated Electric Transmission and Distribution Utility				
	Docket Number:	2009.9.129			
	Order Number :	7046i			
	Effective Date:	July 8, 2011			
	Common Equity		48.00%	10.25%	4.92%
	Long Term Debt		52.00%	5.76%	3.00%
	TOTAL		100.00%		7.92%
	Colstrip Unit 4				
	Docket Number:	2008.6.69			
	Order Number :	6925f			
	Effective Date:	January 1, 2009			
	Common Equity		50.00%	10.00%	5.00%
	Long Term Debt		50.00%	6.50%	3.25%
	TOTAL		100.00%		8.25%
	Dave Gates Generating Station				
	Docket Number:	2008.8.95			
	Order Number :	6943e			
	Effective Date:	January 1, 2011			
	Common Equity		50.00%	10.25%	5.13%
	Long Term Debt		50.00%	6.07%	3.03%
	TOTAL		100.00%		8.16%
	Spion Kop Wind				
	Docket Number:	2011.5.41			
	Order Number :	7159l			
	Effective Date:	December 1, 2012			
	Common Equity		48.00%	10.00%	4.80%
	Long Term Debt		52.00%	4.23%	2.20%
	TOTAL		100.00%		7.00%
	Hydro Assets				
	Docket Number:	2013.12.85			
	Order Number :	7323k			
	Effective Date:	November 18, 2014			
	Common Equity		48.00%	9.80%	4.70%
	Long Term Debt		52.00%	4.25%	2.21%
	TOTAL		100.00%		6.91%

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 151,208,862	$ 120,686,353	25.29%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	125,834,295	112,991,164	11.37%
6	Amortization, Net	18,614,228	10,574,124	76.04%
7	Other Noncash Charges to Net Income, Net	12,638,644	12,431,796	1.66%
8	Deferred Income Taxes, Net	35,501,079	(7,411,618)	>300.00%
9	Investment Tax Credit Adjustments, Net	(232,401)	(273,079)	14.90%
10	Change in Operating Receivables, Net	13,822,901	5,776,323	139.30%
11	Change in Materials, Supplies & Inventories, Net	1,348,472	761,534	77.07%
12	Change in Operating Payables & Accrued Liabilities, Net	(35,847,807)	(1,627,921)	>-300.00%
13	Allowance for Funds Used During Construction (AFUDC)	(8,676,344)	(6,551,852)	-32.43%
14	Change in Other Assets & Liabilities, Net	34,977,392	(6,542,680)	>300.00%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(3,500,544)	(4,314,407)	18.86%
17	Change in Regulatory Assets	(11,042,720)	7,306,869	-251.13%
18	Change in Regulatory Liabilities	3,051,344	3,617,352	-15.65%
19	**Net Cash Provided by Operating Activities**	337,697,401	247,423,958	36.49%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(428,647,576)	(1,172,692,087)	63.45%
22	(Net of AFUDC)			
23	Proceeds from Sale of Assets	30,209,495	1,535,499	>300.00%
24	Other Investing activities	16,108,464	(34,527,780)	146.65%
25	**Net Cash Used in Investing Activities**	(382,329,617)	(1,205,684,368)	68.29%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	270,000,000	505,789,025	-46.62%
29	Issuance of Short Term Borrowings, Net	-	126,890,525	-100.00%
30	Proceeds From Issuance of Common Stock, Net	56,650,930	399,207,125	-85.81%
31	Payments for Retirement of:			
32	Capital Lease Obligations, Net	(24,683)	(89,403)	72.39%
33	Repayments of Short Term Borrowings, Net	(37,965,635)	-	-
34	Long-term Debt	(150,000,000)	-	-
35	Dividends on Common Stock	(90,057,412)	(65,019,105)	-38.51%
36	Other Financing Activities:			
37	Debt Financing Costs	(12,082,801)	(5,247,637)	-130.25%
38	Treasury Stock Activity	(663,706)	(814,026)	18.47%
39	**Net Cash Provided by Financing Activities**	35,856,694	960,716,504	-96.27%
40	**Net (Decrease)/Increase in Cash and Cash Equivalents**	(8,775,522)	2,456,094	>-300.00%
41	**Cash and Cash Equivalents at Beginning of Year**	12,883,654	10,427,560	23.55%
42	**Cash and Cash Equivalents at End of Year**	$ 4,108,132	$ 12,883,654	-68.11%
43				
44	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
45	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
46	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
47	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.			
48				

Sch. 24	MONTANA LONG TERM DEBT 1/								
	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
1									
2	**First Mortgage Bonds**								
3	6.34% Series, Due 2019	03/26/09	04/01/19	$ 250,000,000	$ 247,657,313	$ 249,945,562	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	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%
6	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%
7	4.30% Series($40M), Due 2052	08/10/12	08/10/52	40,000,000	39,748,886	40,000,000	4.30%	1,726,280	4.32%
8	4.85% Series($65M), Due 2043	12/19/13	12/19/43	15,000,000	14,929,953	15,000,000	4.85%	730,647	4.87%
9	3.99% Series($35M), Due 2028	12/19/13	12/19/43	35,000,000	34,836,556	35,000,000	3.99%	1,409,343	4.03%
10	4.176% Series($450M), Due 2044	11/14/14	11/14/44	450,000,000	445,743,514	450,000,000	4.18%	19,570,057	4.35%
11	3.11% Series($75M), Due 2025	06/23/15	07/01/2025	75,000,000	74,563,893	75,000,000	3.11%	2,746,650	3.66%
12	4.11% Series($125M), Due 2045	06/23/15	07/01/2045	125,000,000	124,273,156	125,000,000	4.11%	5,367,425	4.29%
13	**Total First Mortgage Bonds**			$ 1,266,000,000	$ 1,255,902,235	$ 1,265,945,562		$ 62,311,821	4.92%
14									
15	**Pollution Control Bonds**								
16	4.65% Series, Due 2023	04/27/06	08/01/23	$ 170,205,000	$ 164,451,956	$ 170,205,000	4.650%	$ 8,467,855	4.98%
17									
18	**Total Pollution Control Bonds**			$ 170,205,000	$ 164,451,956	$ 170,205,000		$ 8,467,855	4.98%
19									
20	**Other Long-Term Debt**								
21	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%	$ 337,904	1.25%
22									
23	**Total Other Long Term Debt**			$ 26,976,900	$ 26,292,348	$ 26,976,900		$ 337,904	1.25%
24									
25	**TOTAL LONG TERM DEBT**			$ 1,463,181,900	$ 1,446,646,538	$ 1,463,127,462		$ 71,117,580	4.86%
26									
27									
28	This schedule does not reflect our capital lease, which is the Basin Creek contract lease. That amount is $26,325,495.								
29									
30									
31									
32									
33									
34									
35									
36									
37									
38									
39									
40									
41									
42									

Sch. 25	PREFERRED STOCK									
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	Not Applicable									
3										
4										
5										
6										
7										
8										
9										
10										
11										
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21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	TOTAL									

Sch. 26	COMMON STOCK							
	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	46,918,494	$31.99				$59.10	$55.68	
February	47,008,254	32.28				58.08	53.04	
March	47,038,040	32.02	$1.09	$0.48		54.71	50.97	
April	47,040,088	32.19				54.19	52.09	
May	47,041,968	32.31				52.67	50.87	
June	47,062,217	32.23	0.65	0.48		52.03	48.75	
July	47,064,183	32.48				53.84	48.98	
August	47,065,876	32.64				56.32	51.49	
September	47,067,963	32.27	0.51	0.48		53.83	49.31	
October	48,168,586	32.86				56.86	53.73	
November	48,170,413	33.18				54.84	52.40	
December	48,172,158	33.22	0.95	0.48		55.30	52.68	
TOTAL Year End	47,298,350	$33.22	$3.20	$1.92	40.00%	$55.21		17.3

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2015.

Sch. 27	MONTANA EARNED RATE OF RETURN - ELECTRIC				
		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$3,464,258,801	$2,613,915,606	32.53%
3	108	Accumulated Depreciation	(1,065,555,165)	(999,214,380)	-6.64%
4					
5	**Net Plant in Service**		$2,398,703,636	$1,614,701,226	48.55%
6		Additions:			
7	154, 156	Materials & Supplies	$15,027,249	$14,241,167	5.52%
8	165	Prepayments			
9		Other Additions 1/	197,254,539	147,864,538	33.40%
10					
11	**Total Additions**		$212,281,788	$162,105,705	30.95%
12		Deductions:			
13	190	Accumulated Deferred Income Taxes	$334,601,018	$272,701,978	22.70%
14	252	Customer Advances for Construction	26,185,128	22,758,364	15.06%
15	255	Accumulated Def. Investment Tax Credits			
16		Other Deductions	39,976,713	35,432,738	12.82%
17					
18	**Total Deductions**		$400,762,859	$330,893,080	21.12%
19	**Total Rate Base**		$2,210,222,565	$1,445,913,851	52.86%
20	**Net Earnings**		$ 165,672,619	$ 122,440,308	35.31%
21	**Rate of Return on Average Rate Base**		7.496%	8.468%	-11.48%
22	**Rate of Return on Average Equity 2/**		9.892%	11.334%	-12.72%
23					
24		**Major Normalizing and**			
25		**Commission Ratemaking Adjustments**			
26		Rate Schedule Revenues	$4,431,011	($146,710)	>300.00%
27		Income Tax from 2013 and prior 3/	-	(3,729,470)	100.00%
28					
29					
30		Non-Allowables:			
31		Advertising	497,458	527,288	-5.66%
32		Dues, Contributions, Other	112,831	99,844	13.01%
33					
34		Associated Income Taxes 4/	(1,615,507)	(127,233)	>-300.00%
35					
36	**Total Adjustments**		$3,425,793	($3,376,282)	201.47%
37	**Revised Net Earnings**		$169,098,412	$119,064,026	42.02%
38		**Rate Base Adjustment**			
39		Stipulation with MCC 5/	($20,801,999)	($21,667,666)	4.00%
40					
41	**Revised Rate Base**		$2,189,420,566	$1,424,246,185	53.72%
42	**Adjusted Rate of Return on Average Rate Base**		7.723%	8.360%	-7.61%
43	**Adjusted Rate of Return on Average Equity 2/**		10.273%	11.007%	-6.67%

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

2/ Return on Equity calculated using the capital structure approved in Docket No. D2009.9.129, Docket No. D2008.6.69, Docket No. D2008.8.95, Docket No. D2011.5.41 and Docket No. D2013.12.85.

3/ Income tax related to repairs deduction for years prior to 2014.

4/ Associated Income taxes include an Interest synchronization adjustment based upon the approved capital structure in Docket No.D2009.9.129, Docket No. D2008.6.69, Docket No. D2008.8.95, Docket No. D2011.5.41 and Docket No. D2013.12.85.

5/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting two-thirds of the $38.8 million allocated to electric as a rate base reduction.

Sch. 27	cont. MONTANA EARNED RATE OF RETURN - ELECTRIC			
	Description	This Year	Last Year	% Change
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset	$187,617,927	$141,187,188	32.89%
4	Cost of Refinancing Debt	7,558,377	4,593,017	64.56%
5	Fuel Stock	2,078,235	2,084,333	-0.29%
8	**Total Other Additions**	$197,254,539	$147,864,538	33.40%
10	**Detail - Other Deductions**			
11	Personal Injury and Property Damage	$5,727,831	$5,492,439	4.29%
12	Gross Cash Requirements	34,248,882	29,940,299	14.39%
13	MPSC/MCC Taxes	-	-	-
16	**Total Other Deductions**	$39,976,713	$35,432,738	12.82%

Sch. 28	MONTANA COMPOSITE STATISTICS - ELECTRIC (EXCLUDES YNP)		
	Description		Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$ 3,251,222,977
5	103	Experimental Electric Plant Unclassified	658,807
6	105	Plant Held for Future Use	3,778,101
7	107	Construction Work in Progress	51,666,842
8	114	Plant Acquisition Adjustments	350,704,330
9	151-163	Materials & Supplies	21,501,829
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	1,095,271,692
12	252	Contributions in Aid of Construction	28,741,784
13	**NET BOOK COSTS**		2,555,519,410
14			
15		**Revenues & Expenses**	
16			
17	400	Operating Revenues	824,724,531
18			
19	**Total Operating Revenues**		824,724,531
20			
21	401-402	Other Operating Expenses (including regulatory amortizations)	429,008,362
22	403-407	Depreciation & Amortization Expenses	101,778,508
23	408.1	Taxes Other than Income Taxes	105,083,939
24	409-411	Federal & State Income Taxes	23,181,105
25	411.8	SO2 Allowances	(2)
26			
27	**Total Operating Expenses**		659,051,912
28	**Net Operating Income**		165,672,619
29			
30	415-421.1	Other Income	3,119,693
31	421.2-426.5	Other Deductions	590,297
32	**NET INCOME BEFORE INTEREST EXPENSE**		$ 168,202,015
33			
34		**Average Customers (Intrastate Only)**	
35		Residential	287,213
36		Commercial & Industrial	66,090
37		Other (including interdepartmental)	4,046
38			
39	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		357,349
40			
41		**Other Statistics (Intrastate Only)**	
42		Average Annual Residential Use (Kwh)	8,205
43		Average Annual Residential Cost per (Kwh)	$0.118
44		Average Residential Monthly Bill	$80.79
45			
46		Plant in Service (Gross) per Customer	$9,098

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,150	478	115	5	598
2	Alberton	420	381	85	12	478
3	Alder	103	213	82	20	315
4	Amsterdam	180	129	39	8	176
5	Anaconda	9,298	4,266	817	48	5,131
6	Armington	-	1	-	-	1
7	Arrow Creek	-	4	5	-	9
8	Augusta	309	252	109	3	364
9	Avon	111	93	64	3	160
10	Barber	-	49	12	1	62
11	Basin	212	160	74	1	235
12	Bearcreek	79	64	21	3	88
13	Belfry	218	185	67	16	268
14	Belgrade	7,389	7,631	1,819	92	9,542
15	Belt	597	638	245	16	899
16	Benchland	-	6	6	-	12
17	Big Sandy	598	338	140	5	483
18	Big Sky	2,308	3,486	831	26	4,343
19	Big Timber	1,641	1,224	406	28	1,658
20	Billings	104,170	47,229	8,265	684	56,178
21	Black Eagle	904	460	165	14	639
22	Bonner	1,663	78	38	1	117
23	Boulder	1,183	836	254	25	1,115
24	Box Elder	87	145	64	9	218
25	Bozeman	37,280	28,147	5,788	386	34,321
26	Brady	140	92	40	4	136
27	Bridger	708	439	167	13	619
28	Broadview	192	227	157	3	387
29	Buffalo	-	-	1	4	5
30	Butte	33,525	14,790	2,564	280	17,634
31	Cameron	-	361	114	6	481
32	Canyon Creek	-	187	41	7	235
33	Carter	58	116	73	3	192
34	Cascade	685	1,106	308	26	1,440
35	Centerville	-	13	11	1	25
36	Checkerboard	-	53	9	1	63
37	Chester	847	481	304	16	801
38	Chinook	1,203	806	313	15	1,134
39	Choteau	1,684	1,004	374	26	1,404
40	Churchill	902	705	141	25	871
41	Clancy	1,661	852	152	10	1,014
42	Clinton	1,052	103	34	2	139
43	Coffee Creek	-	58	23	1	82
44	Colstrip	2,214	978	204	33	1,215
45	Columbus	1,893	1,012	338	18	1,368
46	Conrad	2,570	1,270	482	28	1,780
47	Corbin	-	1	2	-	3
48	Corvallis	976	794	177	39	1,010
49	Craig	43	95	34	6	135
50	Custer	159	1	3	-	4

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Darby	720	786	251	19	1,056
2	De Borgia	78	148	34	2	184
3	Deer Lodge	3,111	2,087	595	74	2,756
4	Denton	255	181	83	1	265
5	Dillon	4,134	2,012	540	60	2,612
6	Divide	-	67	14	3	84
7	Dodson	124	113	68	6	187
8	Drummond	309	367	215	26	608
9	Dutton	316	243	121	4	368
10	East Helena	1,984	2,938	405	27	3,370
11	Edgar	114	175	55	7	237
12	Elliston	219	201	59	3	263
13	Ennis	838	1,720	564	34	2,318
14	Fairfield	708	404	161	28	593
15	Fishtail	-	24	3	-	27
16	Florence	765	385	143	15	543
17	Floweree	-	107	56	1	164
18	Fort Belknap	1,293	458	106	23	587
19	Fort Benton	1,464	823	354	32	1,209
20	Fort Harrison	-	-	92	3	95
21	Fromberg	438	313	76	10	399
22	Gallatin Gateway	856	704	183	13	900
23	Gardiner	875	793	296	11	1,100
24	Garrison	96	118	62	6	186
25	Geraldine	261	282	156	2	440
26	Geyser	87	64	37	4	105
27	Gildford	179	91	66	2	159
28	Glasgow	3,250	1,678	710	62	2,450
29	Glasgow Air Base		1	1	-	2
30	Gold Creek	-	77	38	3	118
31	Grantsdale	-	26	3	1	30
32	Great Falls	58,505	29,125	5,235	384	34,744
33	Greycliff	112	53	31	9	93
34	Hall	-	267	77	16	360
35	Hamilton	4,348	5,349	1,419	117	6,885
36	Hardin	3,505	1,422	450	25	1,897
37	Harlem	808	436	203	25	664
38	Harlowton	997	673	276	8	957
39	Harrison	137	180	58	24	262
40	Haugan	-	80	37	2	119
41	Havre	10,026	4,904	1,187	185	6,276
42	Helena	53,457	24,340	5,088	425	29,853
43	Hingham	118	107	72	2	181
44	Hinsdale	217	138	50	7	195
45	Hobson	215	166	61	9	236
46	Huson	210	140	35	1	176
47	Inverness	55	40	27	1	68
48	Jardine	57	1	1	-	2
49	Jeffers	-	3	1	-	4
50	Jefferson City	472	317	54	3	374
51	Joliet	595	480	131	18	629

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Joplin	157	98	49	2	149
2	Judith Gap	126	87	53	7	147
3	Kremlin	98	70	35	1	106
4	Laurel	6,718	3,208	485	24	3,717
5	Lavina	187	190	100	13	303
6	Lennep	-	20	11	-	31
7	Lewistown	5,910	3,346	916	51	4,313
8	Lincoln	1,013	1,062	266	15	1,343
9	Livingston	7,044	4,736	1,132	60	5,928
10	Logan	99	58	24	2	84
11	Lohman	-	31	32	5	68
12	Lolo	3,892	1,483	193	17	1,693
13	Loma	85	68	39	3	110
14	Lothair	-	16	11	-	27
15	Malta	1,997	1,329	494	46	1,869
16	Manhattan	1,520	1,118	314	82	1,514
17	Martinsdale	64	129	83	10	222
18	Marysville	80	72	34	2	108
19	Maxville	130	5	-	-	5
20	McAllister	-	222	46	7	275
21	Melrose	-	1	-	-	1
22	Melstone	96	166	275	20	461
23	Melville	-	73	56	4	133
24	Milltown	-	76	19	3	98
25	Missoula	66,788	36,179	6,479	615	43,273
26	Moccasin	-	45	32	1	78
27	Molt	-	29	31	-	60
28	Monarch	-	327	57	5	389
29	Montana City	2,715	1,081	197	3	1,281
30	Moore	193	109	43	5	157
31	Musselshell	60	61	28	-	89
32	Nashua	290	201	66	3	270
33	Neihart	51	198	38	3	239
34	Nevada City	-	-	7	-	7
35	Norris	-	56	44	2	102
36	Nye	-	38	5	1	44
37	Paradise	163	161	59	9	229
38	Park City	983	436	77	5	518
39	Philipsburg	820	1,805	343	24	2,172
40	Plains	1,048	1,621	464	27	2,112
41	Pompey's Pillar		1	-	-	1
42	Pony	118	131	27	4	162
43	Power	179	87	47	2	136
44	Pray	681	25	1	1	27
45	Radersburg	66	82	25	1	108
46	Ramsay	-	60	30	1	91
47	Raynesford	-	67	35	2	104
48	Red Lodge	2,125	1,981	406	24	2,411
49	Reedpoint	193	168	58	3	229
50	Ringling	-	43	29	3	75
51	Roberts	-	1	-	-	1
52	Rocker	-	57	21	2	80

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	408	21	1,526
4	Rudyard	258	154	62	2	218
5	Ryegate	245	145	70	11	226
6	Saco	197	159	100	5	264
7	Saint Marie	264	300	47	3	350
8	Saint Regis	319	490	176	14	680
9	Saltese	-	39	22	1	62
10	Sand Coulee	212	155	50	4	209
11	Sapphire Village	-	64	7	-	71
12	Shawmut	42	53	34	3	90
13	Sheridan	642	919	249	41	1,209
14	Silesia	96	41	8	1	50
15	Silverbow	-	12	5	1	18
16	Springdale	42	39	14	8	61
17	Square Butte	-	38	25	1	64
18	Stanford	401	336	209	7	552
19	Stevensville	1,809	2,036	569	76	2,681
20	Stockett	169	159	58	3	220
21	Sumatra	-	-	3	-	3
22	Superior	812	898	275	26	1,199
23	Taft	-	-	2	-	2
24	Tampico	-	11	6	-	17
25	Thompson Falls	1,313	1,098	357	31	1,486
26	Three Forks	1,869	1,397	498	61	1,956
27	Toston	108	51	40	25	116
28	Townsend	1,878	1,282	346	24	1,652
29	Tracy	-	92	12	4	108
30	Turah	306	16	2	-	18
31	Twin Bridges	375	310	156	23	489
32	Twodot	-	51	49	5	105
33	Ulm	738	427	120	12	559
34	Utica	-	2	5	1	8
35	Valier	509	376	186	35	597
36	Vaughn	658	247	45	8	300
37	Victor	745	806	272	25	1,103
38	Virginia City	190	190	106	2	298
39	Wagner	-	46	24	1	71
40	Walkerville	675	255	29	3	287
41	Warm Springs	-	-	3	-	3
42	Washoe	-	7	2	-	9
43	West Yellowstone	1,271	2	11	-	13
44	White Sulphur Springs	939	807	377	56	1,240
45	Whitehall	1,038	1,005	285	58	1,348
46	Wickes	-	1	-	-	1
47	Williamsburg	-	1	1	-	2
48	Willow Creek	210	141	57	19	217
49	Windham	-	46	32	2	80
50	Winston	147	134	47	3	184

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Wolf Creek	-	411	164	10	585
2	Yellowstone Club	-	312	3	-	315
3	Zurich	-	108	81	11	200
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48						
49	**Total**	502,689	287,213	64,653	5,483	357,349

1/ Customer populations represent an average of the 12 month period from 01/01/15 through 12/31/15. YNP customer counts have been excluded.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	155	156	156
5	Finance	138	149	144
6	Regulatory Affairs	28	28	28
7	Distribution	517	455	486
8	Transmission	273	327	300
9	Supply	121	122	122
10	Legal	20	22	21
11				
12				
13				
14				
15				
16				
17				
18	TOTAL EMPLOYEES	1,254	1,261	1,258

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2016 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Elec Distribution - Elec Distribution Infrastructure Plan	$46,673,415	$46,673,415
4	MT Elec Trans - Columbs-Rapelje to Chrome Jct 100kv line	15,395,382	15,395,382
5	MT Elec Trans - NERC Facilities Compliance 230/161 and 115/10	9,731,193	9,731,193
6	MT Elec Trans - Jack-Rabbit-Big Sky 161kV Line	7,266,208	7,266,208
7	MT Elec Transmission - Dakota Access Pumping Station sub	6,549,178	0
8	MT Elec Trans - Bozeman-Big Sky Meadow Village 161 Sub Rebui	5,000,000	5,000,000
9	MT Electric - substation infrastructure improvements	5,000,000	5,000,000
10	MT Elec Trans - Stevensville A&B Line loop	4,015,452	4,015,452
11	MT Elec Trans - Yellowtail-Billings 230kv permit renewal	3,400,068	3,400,068
12	MT Elec Trans - Crooked Falls Switchyard expansion	2,733,672	2,733,672
13	MT Elec Trans - Fort Benton-Kershaw substation switchyard	2,600,000	2,600,000
14	SD Elec - Aberdeen City Sub clearance corrections	2,497,152	0
15	SD Elec - Redfield City Sub clearance corrections	2,496,884	0
16	MT Elec Distribution - Phillipsburg substation	2,331,829	2,331,829
17	MT Elec Trans - Dillon-Salmon 161-69 Auto Bank upgrade	2,155,261	2,155,261
18	MT Elec Distribution - Big Sky Lone Mountain Sub Bank upgrade	2,000,000	2,000,000
19	MT Elec - MT Community Solar	1,500,000	1,500,000
20	MT Elec Distribution - Missoula Target Range Sub Circuit Breaker	1,486,650	1,486,650
21	MT Elec Trans - Colstrip spare Autobank transformer	1,164,392	1,164,392
22	All Other Projects < $1 Million Each	77,933,198	57,755,430
23			
24	**Total Electric Utility Construction Budget**	**201,929,934**	**170,208,952**
25			
26	**Natural Gas Operations**		
27	MT Gas Trans - Meriwether-Kalispell Horse Power	5,760,574	5,760,574
28	MT Gas Retail - Gas Distribution Infrastructure Plan	5,172,632	5,172,632
29	MT Gas Trans - GTIP Bozeman East Reroute& USM living	3,925,514	3,925,514
30	MT Gas Trans - GTIP Bozeman West and CG2 HCA	3,725,550	3,725,550
31	MT Gas Trans - Station W horsepower	2,189,130	2,189,130
32	MT Gas Retail - Gas One service replace, meter move outs, other	1,399,516	1,399,516
33	MT Gas Trans - Two Medicine Pipeline exposure	954,468	954,468
34	All Other Projects < $1 Million Each	20,733,316	15,850,076
35			
36	**Total Natural Gas Utility Construction Budget**	43,860,700	38,977,460
37			
38	**Common**		
39	MT and SD Fleet and Equipment upgrades	7,075,387	4,901,387
40	SD Facilities lease buyout	4,000,000	0
41	MT Business Tech - SAP PRA-JVA and Quorum Gas Prod Softwa	2,885,794	2,885,794
42	MT Communications fiber backbone	2,857,475	1,900,852
43	MT Facilities - Havre Service center upgrade	965,633	965,633
44	MT Business Tech - LD Pro to DDS estimating software upgrade	918,116	918,116
45	All Other Projects < $1 Million Each	10,745,412	8,411,309
46	(Includes IT, Communications, Facilities, Cust Serv)		
47			
48			
49	**Total Common Utility Construction Budget**	29,447,817	19,983,091
50			
51	MT CU4 capital additions - PPL invoice	12,248,000	12,248,000
52	MT - Hydro Generation upgrades	12,730,178	12,730,178
53	MT - DGGS 25k hour overhauls and other	2,532,228	2,532,228
54	SD Big Stone, Neal 4, Coyote partner capital	3,826,727	0
55	All Other Projects < $1 Million Each	1,528,415	50,000
56			
57			
58			
59	**Total MT/SD Generation**	32,865,548	27,560,406
60	**TOTAL CONSTRUCTION BUDGET**	**$308,104,000**	**$256,729,909**

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	4	18:00	2,229	1,006,664	371,468
2	February	23	8:00	2,109	811,494	311,415
3	March	3	20:00	2,093	829,560	243,102
4	April	6	10:00	1,961	801,631	296,011
5	May	8	10:00	1,854	803,719	300,956
6	June	29	17:00	2,387	819,854	343,530
7	July	1	17:00	2,308	733,804	294,675
8	August	13	17:00	2,322	746,339	206,089
9	September	2	17:00	2,078	724,817	218,001
10	October	29	20:00	1,937	666,997	165,491
11	November	30	19:00	2,162	650,167	168,295
12	December	30	18:00	2,197	707,670	150,059
13	**TOTALS**				9,302,716	3,069,092
14		Montana Peak and Energy				
15		Peak	Peak	Peak Day Volume	Total Monthly Volumes	Non-Requirements
16		Day	Hour	Megawatts	Energy (Mwh)	Sales For Resale (Mwh)
17	January					
18	February					
19	March					
20	April					
21	May					
22	June					
23	July			SAME AS ABOVE		
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	1,650,773		
3	Nuclear	-	**Sales to Ultimate Consumers**	5,960,466
4	Hydro - Conventional	3,278,130	(Include Interdepartmental) 1/	
5	Hydro - Pumped Storage	-		
6	Other	553,539	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	
8	**Net Generation**	5,482,442	Non-Requirement Sales	3,069,092
9	**Purchases**	3,821,531	**Sales for Resale**	3,069,092
10	Power Exchanges			
11	Received	40,725		
12	Delivered	41,982	Energy Furnished w/o Charge	-
13	**Net Power Exchanges**	(1,257)	**Energy Furnished**	-
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	11,283,586	Electric Department	
16	Delivered	11,283,586	(Less) Station Use	-
17	**Net Transmission Wheeling**	-	**Net Energy Used Within Util.**	-
18	**Transmission by Others Losses**	-	**Energy Losses**	273,158
19	**TOTAL SOURCES**	9,302,716	**TOTAL DISPOSITIONS**	9,302,716

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 7,236 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	1,650,773
2	Gas Turbine Generation	Dave Gates Station	Anaconda, MT	150.0	426,102
3	Wind Generation	Spion Kop	Judith Basin County, MT	40.0	127,437
4	Hydro Generation	Black Eagle	Great Falls, MT	21.0	127,279
5	Hydro Generation	Cochrane	Great Falls, MT	64.0	260,568
6	Hydro Generation	Hauser	Helena, MT	19.0	122,257
7	Hydro Generation	Holter	Helena, MT	48.0	258,627
8	Hydro Generation	Kerr	Polson, MT	194.0	827,255
9	Hydro Generation	Madison	Ennis, MT	8.0	59,401
10	Hydro Generation	Morony	Great Falls, MT	48.0	247,097
11	Hydro Generation	Mystic	Columbus, MT	12.0	57,481
12	Hydro Generation	Rainbow	Great Falls, MT	64.0	347,742
13	Hydro Generation	Ryan	Great Falls, MT	60.0	447,914
14	Hydro Generation	Thompson Falls	Thompson Falls, MT	94.0	522,509
15	Total Generation			1,044.0	5,482,442
16	Purchases	Small Power Producers	Colstrip Energy, Ltd.	3.3	294,033
17	Purchases	Small Power Producers	Billings Generation, Inc.	5.1	500,087
18	Purchases	Small Power Producers	State of Montana - DNRC	0.9	47,296
19	Purchases	Small Power Producers	Gordon Butte Wind	0.8	35,651
20	Purchases	Small Power Producers	Foundation Windpower LLC	0.9	31,605
21	Purchases	Small Power Producers	Two Dot Wind Farm	0.9	29,844
22	Purchases	Small Power Producers	Musselshell Wind 1	0.9	24,055
23	Purchases	Small Power Producers	Musselshell Wind 2	0.8	28,257
24	Purchases	Small Power Producers	Others	0.9	33,584
25	Subtotal			14.5	1,024,412
26	Purchased Power		Avista Corporation	0.0	104,902
27	Purchased Power		Barclays Bank PLC	0.0	40,800
28	Purchased Power		Basin Electric Power Cooperative	0.0	80,089
28	Purchased Power		Basin Power Plant	0.0	63,137
29	Purchased Power		Black Hills Power Inc.	0.0	8,715
30	Purchased Power		Bonneville Power Administration	0.0	25,245
31	Purchased Power		Cargill Power Markets LLC	0.0	39,197
32	Purchased Power		Citigroup Energy, Inc.	0.0	227,200
33	Purchased Power		Clark County PUD No. 1	0.0	2,298
34	Purchased Power		Shell Energy North America	0.0	14,179
35	Purchased Power		Credit Suisse Energy LLC	0.0	35,420
36	Purchased Power		Deutsche Bank Energy Trading	0.0	10,400
37	Purchased Power		Energy Keepers, Inc.	0.0	548
38	Purchased Power		Eugene Water & Electric Board	0.0	305
39	Purchased Power		Grant County PUD No. 2	0.0	35
40	Purchased Power		Iberdrola Renewables, LLC	0.0	474,212
41	Purchased Power		Idaho Power Company	0.0	6,726
42	Purchased Power		Invenergy Energy markets LLC	0.0	138,933
43	Purchased Power		Judith Gap Invenergy Energy Marketing	0.0	309,606
44	Purchased Power		Macquarie Energy LLC	0.0	370
45	Purchased Power		Merrill Lynch Commodities, Inc.	0.0	8,200
46	Purchased Power		Morgan Stanley Capital Group, Inc.	0.0	405,614
47	Purchased Power		PacifiCorp	0.0	64,180
48	Purchased Power		Portland General Electric	0.0	23,104
49	Purchased Power		Powerex Corp.	0.0	23,619
50	Purchased Power		Talen Energy Marketing, LLC	0.0	158,079
51	Purchased Power		Puget Sound Energy	0.0	31,195
52	Purchased Power		Rainbow Energy Marketing Corporation	0.0	39,000
53	Purchased Power		Seattle City Light	0.0	21,624
54	Purchased Power		Southern California Edison	0.0	3,687
55	Purchased Power		Tacoma Power	0.0	5,690
56	Purchased Power		Tenaska Power Services	0.0	665
57	Purchased Power		The Energy Authority, Inc.	0.0	15,893
58	Purchased Power		Tiber Dam, LLC	0.0	48,969
59	Purchased Power		TransAlta Energy Marketing (US)	0.0	329,156
60	Purchased Power		Turnbull Hydro, LLC	0.0	25,123
61	Purchased Power		Twin Eagle Resource Management, LLC	0.0	1,375
62	Subtotal			0.0	2,787,490
63	System Balancing Transactions		Coral/Shell Energy	0.0	7,928
64	Reserve Sharing				1,701
65	Total Purchases				3,821,531

Sch. 34A	THERMAL GENERATION OUTAGE REPORT			
	Unit	**Outage Start Date**	**Description**	**Outage Duration (hours)**
1	**Colstrip Unit 3**	3/17/2015	Leak on boiler circulating pump purge line	31
3		3/25/2015	Unit trip to transformer sudden pressure relay	29
5		4/11/2015	Auxiliary transformer scheduled outage	18
7		5/5/2015	Coal pulverizer electrical fault	61
9		5/9/2015	Boiler tube leak	76
11		5/12/2015	Electronic turbine latch issue	12
13		7/15/2015	Boiler tube leak	48
15		12/2/2015	Boiler tube leak	72
17		12/5/2015	Tube leak	44
20	**Colstrip Unit 4**	1/31/2015	Boiler tube leak	72
22		2/3/2015	Leak on bleeder trip valve	20
24		4/24/2015	Boiler tube leak	50
26		5/1/2015	Turbine lube oil cooler leak	71
28		8/29/2015	Tube leak repair	13
30		11/13/2015	Tube leak repairs	67

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)**
DGGS Unit 1	1/1/2015	Failed bearing	87
	1/8/2015	Prepare unit for power turbine removal	273
	4/3/2015	Low tank level and high bearing vibration	24
	4/12/2015	Low oil pressure, suspected bearing failure	99
	6/15/2015	Removal and replacement of gas generator	65
	8/4/2015	Scheduled borescope inspection	13
	11/16/2015	Combustion turbine and diffuser seal ring replacement	105
DGGS Unit 2	1/1/2015	Gas generator repair and reinstallation	95
	1/4/2015	Unit 2A engine offsite for repairs	4,310
DGGS Unit 3	1/1/2015	Gas generator bearing seal damage	1,709
	1/5/2015	Expansion joint removal and blanking plate installation	40
	5/26/2015	Install power turbine and gas generator	89
	5/30/2015	Correct power turbine alignment	86
	6/20/2015	Annual boroscope inspection	37
	11/3/2015	Exhaust case welding repair	12

Only outages greater than 12 hours are reported.

HYDRO GENERATION OUTAGE REPORT

Plant	Unit Name	Outage Start Date	Description	Outage Duration (hours)
Black Eagle	BE1	9/14/2015	Annual condition assessment outage	2,610
	BE2	1/1/2015	Convert turbine bearing from oil to marine	1,380
	BE2	2/27/2015	Vibration issues	311
	BE2	8/2/2015	Cracked valve on bearing cooling water line	358
	BE2	12/15/2015	Vibration in turbine	400
	BE3	8/18/2015	Inspect turbine and maintenance	412
Hauser	HAU1	5/11/2015	Upgrade generator protective relay	31
	HAU2	5/5/2015	Upgrade generator protective relay	29
	HAU2	10/19/2015	Governor PLC upgrade	219
	HAU3	3/16/2015	Overhaul - major rehabilitation	6,977
	HAU4	5/7/2015	Upgrade generator protective relay	32
	HAU5	1/5/2015	Inspect and take measurements	29
	HAU5	5/13/2015	Upgrade generator protective relay	29
	HAU5	10/19/2015	Governor PLC upgrade and testing	242
	HAU6	2/17/2015	Exciter problem	22
	HAU6	5/19/2015	Upgrade generator protective relay	32
	HAU6	5/22/2015	Hot generator breaker	102
	HAU6	10/26/2015	Upgrade exciter to static system	99
Cochrane	CCH2	11/12/2015	Annual condition assessment outage	1,038
Holter	HLT1	2/15/2015	Annual condition assessment and maintenance	1,697
	HLT1	5/20/2015	Governor trouble	24
	HLT1	10/10/2015	Speed sensor failing	66
	HLT1	11/17/2015	High wind issues	359
	HLT2	7/22/2015	Annual condition assessment	1,038
	HLT3	4/19/2015	Voltage problem	81
	HLT3	9/2/2015	Annual condition assessment outage	1,484
	HLT4	11/17/2015	Annual outage	986
Kerr	KER1	6/14/2015	Dirty, worn field brushes	18
Madison	MAD1	4/6/2015	Replace thrust block	216
	MAD2	2/15/2015	Governor trouble	41
	MAD3	4/27/2015	Annual maintenance	47
	MAD4	4/15/2015	Minor miscellaneous maintenance	286
Morony	MOR1	1/19/2015	Warranty work on stator	2,040
	MOR1	4/20/2015	Air gap work	99
	MOR1	5/1/2015	Work on rotor	78
	MOR1	7/27/2015	Annual condition assessment outage	241
	MOR2	8/6/2015	Corona damage to exciter power leads	30
Mystic	MYS1	2/23/2015	Rewedge stator and replace rotor pole keys	465
	MYS1	4/7/2015	PCS card shorted out	54
	MYS2	3/16/2015	Overhaul and re-key rotor poles	171
Rainbow	RNB9	4/13/2015	Andritz settlement repairs, GGB pump replacement	202
	RNB9	4/21/2015	HPL pump work	47
Ryan	RYN1	8/18/2015	Turbine inspection and maintenance	246
	RYN2	8/31/2015	Annual condition assessment outage	267
	RYN3	2/5/2015	High stator temperature	88
	RYN3	2/9/2015	Annual maintenance and clean stator	267
	RYN3	6/8/2015	Low system pressure	28
	RYN4	11/30/2015	Annual maintenance	265
	RYN5	12/16/2015	Annual condition assessment outage	369
	RYN6	3/24/2015	Annual condition assessment outage	894
Thompson Falls	THF4	1/13/2015	Annual maintenance	416
	THF5	7/13/2015	Annual condition assessment outage	1,440
	THF6	3/11/2015	Annual maintenance	172
	THF7	9/11/2015	Annual condition assessment outage	741

Only outages greater than 12 hours are reported, excluding low water outages.

Sch. 35	MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS						
	Program Description (These are Electric DSM Programs)	Year Expenditures	Year Expenditures	% Change	Planned Savings (MWH)	Achieved Savings (MWH)	Difference (MWH)
1							
2	2015 Residential Lighting Program	$ 1,283,975	$ 1,286,704	-0.21%	17,188	15,800	(1,388)
3							
4	2015 Commercial Lighting Program	$ 1,360,947	$ 2,004,501	-32.11%	7,740	7,115	(625)
5							
6	2015 E+ Business Partners Program (Electric)	$ 916,456	$ 1,616,456	-43.30%	3,564	3,276	(288)
7							
8	2015 E+ Residential Electric New Construction Program	$ -	$ 4,511	-100.00%	-	-	-
9							
10	2015 E+ Residential Electric Savings Program	$ 716	$ 16,456	-95.65%	-	-	-
11							
12	2015 Northwest Energy Efficiency Alliance (NEEA)*	$ 1,261,896	$ 1,088,651	15.91%	10,208	9,383	(824)
13							
14	2015 E+ Commercial Electric New Construction Program	$ 350,997	$ 76,424	359.28%	3,133	2,880	(253)
15							
16	2015 E+ Commercial Electric Savings Program	$ 790,232	$ 490,113	61.23%	4,896	4,501	(395)
17							
18							
19							
20							
21							
22	A program participant is a Montana residential and/or						
23	commercial electric customer who installs eligible						
24	energy conservation measures and receives financial						
25	incentives/rebates either directly or indirectly.						
26							
27	*Note: 2015 NEEA expeditures are allocated to electric DSM						
28	but there are gas savings as a result of some NEEA Programs.						
29							
30							
31							
32							
33							
34	**TOTAL**	$ 5,965,220	$ 6,583,815	-9.40%	46,728	42,955	(3,773)

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
1	Local Conservation				MWh	MW	
2	E+ Residential Audit/Sm. Comm Audit	$ 218,793	$ 245,963	$ 464,756	750	0.163	2012
3	E+ Business Partners / Irrigation Projects	80,660	-	80,660	556	0.062	2012
4	NWE Promotion	91,923	-	91,923			
5	NWE Labor	34,141	-	34,141			
6	NWE Admin. Non-labor	369	-	369			
7	USB Interest & Svc Chg	(194)	-	(194)			
8	Market Transformation						
9	E+ Commercial Lighting	18,813	-	18,813			
10	Motor Management Training	13,122	-	13,122			
11	Energy Star Homes	131,478	-	131,478			
12	Building Operator Certification	55,306	-	55,306	2,953	-	2012
13	Commercial Industrial Training & Conference	44,101	-	44,101			
14	NWE Promotion	16,541	-	16,541			
15	NWE Labor	19,472	-	19,472			
16	NWE Admin. Non-labor	5,809	-	5,809			
17	USB Interest & Svc Chg	(124)	-	(124)			
18	Renewable Resources						
19	Generation/Education	1,000	687,320	688,320	312	0.238	2012
20	Green Power Product Offering	(19,490)	-	(19,490)			
21	NWE Promotion	5,730	-	5,730			
22	NWE Labor	53,102	-	53,102			
23	NWE Admin. Non-labor	1,685	-	1,685			
24	USB Interest & Svc Chg	(222)	-	(222)			
25	Research & Development						
26	R&D/ Infrastructure	56,490	36,356	92,846			
27	Battery Storage	1,708	-	1,708			
28	Energy Corps	-	-	-			
29	NWE Promotion	5,869	-	5,869			
30	NWE Labor	9,057	-	9,057			
31	NWE Admin. Non-labor	137	-	137			
32	USB Interest & Svc Chg	(51)	-	(51)			
33	Low Income						
34	Bill Assistance	2,340,963	-	2,340,963			
35	Free Weatherization	418,950	1,469,844	1,888,794	239	0.062	2012
36	Elec Wx Incentives	17,465	-	17,465			
37	Fuel Switch Analyses	2,500	-	2,500			
38	Energy Share	289,000	180,849	469,849			
39	NWE Promotion	9,789	-	9,789			
40	NWE Labor	35,727	-	35,727			
41	NWE Admin. Non-labor	1,983	-	1,983			
42	USB Interest & Svc Chg	(1,551)	-	(1,551)			
43	Large Customer Self Directed						
44	Self-Directed Energy Reduction	1,998,831	930,004	2,928,835			
45	Self-Directed to Low Income	20,000	-	20,000			
46	NWE Labor	14,054	-	14,054			
47	USB Interest & Svc Chg	(960)	-	(960)			
48	NWE Allocated from 2014 to cover LC Expense [a]	(11,272)	-	(11,272)			
49	Total	$ 5,980,704	$ 3,550,336	$ 9,531,040	4,810	0.524	
50	Number of customers that received low income rate discounts				11,629		
51	Average monthly bill discount amount ($/mo)				$ 16.78		
52	Average LIEAP-eligible household income				n/a		
53	Number of customers that received weatherization assistance				311 [b]		
54	Expected average annual bill savings from weatherization				768 Kwh		
55	Number of residential audits performed on-site				1,728 [b]		
56	Number of residential audits performed off-site				1,595 [b]		
57	[a] The 2015 Large Customer Admin Costs of $14,054 less the interest income of $960 exceeded the amount of unclaimed 2015 Large Customer funds of $1,822. Northwestern has committed unclaimed 2014 Large Customer funds in the amount of $11,272 to cover the deficit.						
58	[b] Total savings and number of customers is reported for the combination of 2015 electric and natural gas USB funds expended in 2015.						

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	Local Conservation					
2	E+ Energy Audit for the Home or Business	$ 718,793	$ -	$ 718,793	0.20	2012
3					934	
4	E+ Business Partners Program (Electric)	$ -	$ -	$ -	-	2012
5					-	
6	Commercial Lighting					
7	E+ Commercial Lighting Program	$ 18,813	$ -	$ 18,813	-	2012
8					-	
9	Market Transformation					
10	Motor Management Training	$ 13,122	$ -	$ 13,122	-	2012
11					-	
12	Building Operator Certification	$ 55,306	$ -	$ 55,306	-	2012
13					2,953	
14	Regional Market Transformation	$ 44,101	$ -	$ 44,101	-	2012
15					-	
16	Renewables and Research & Development					
17	Generation/Education	$ 679,175	$ -	$ 679,175	0.52	2012
18					681	
19	Green Power Product	$ -	$ -	$ -	-	2012
20					-	
21	R&D / Infrastructure	$ 284,896	$ -	$ 284,896	-	2012
22					-	
23	Low Income					
24	Free Weatherization	$ 778,891	$ -	$ 778,891	-	2012
25					144	
26	Fuel Switch	$ 2,500	$ -	$ 2,500	0.11	2012
27					92	
28	Other					
29	E+ Irrigator Program	$ 80,660	$ -	$ 80,660	0.06	2012
30					556	
31	E+ New Homes Program	$ 131,478	$ -	$ 131,478	-	2012
32					-	
33	Total	$ 2,807,735	$ -	$ 2,807,735	0.895	
34					5,361	

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	**Sales of Electricity**						
2							
3	Residential	$278,440,873	$257,285,796	2,356,643	2,398,535	287,213	283,145
4	Commercial & Industrial	399,659,939	368,828,640	6,228,560	6,115,143	66,090	65,138
5	Public Street & Highway Lighting	16,055,574	15,647,698	59,997	60,206	3,752	3,827
6	Sales to Other Utilities	64,310,070	63,924,368	3,069,092	2,332,656	25	18
7	Interdepartmental	1,194,030	1,125,772	10,948	10,955	294	290
8							
9	**TOTAL SALES**	$759,660,486	$706,812,274	11,725,240	10,917,495	357,374	352,418
10							
11	1/ Revenue and MWHs include unbilled.						
12							
13							
14							
15							
16							