YEAR ENDING 2014

ANNUAL REPORT
OF

NorthWestern Energy
(Townsend Propane)

GAS UTILITY

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

Propane Annual Report

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Sch. 1	IDENTIFICATION

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

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

N/A

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

Reflects active officers as of December 31, 2014.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		$ 117,669	97.50%
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including CMP & HPC) Propane Utility		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		$ 3,017	2.50%
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
NorthWestern Investments, LLC	Holds non-utility assets		
Risk Partners Assurance, Ltd.	Captive insurance company		
Mountain States Transmission Intertie, LLC	Will hold new transmission infrastructure assets		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Total Corporation		$ 120,686	100.00%

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT 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.	$15,201,076	74.01%	$5,338,153
Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Corp Communications & Contributions, CC - Assoc & Dispatch Human Resources and Print Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	24,138,886	73.99%	8,487,106
Legal Department	Includes the following departments: Chief Legal, Record Services, Risk Mgmt	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	11,193,990	80.84%	2,652,477
Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, Business Technology Applications, Security, Data Center, Project Management & Asset Control and Capital Related Exp.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	15,863,291	74.01%	5,571,422
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research, Government Affairs, Reg Support Services, Community Relations & Public Affairs.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	4,029,507	81.03%	943,529
Executive Department	Includes the following departments: CEO, and Board of Directors	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	2,719,342	71.82%	1,067,163
Audit & Controls	Includes the following departments: Internal Audit and Enterprise Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	788,978	73.00%	291,813
Distribution	Includes the following departments: Sioux Falls Facilities and Mail Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	507,309	73.00%	187,635
Hydro Administration	Includes Hydro Administration Exp from the following departments: Marketing Supply Operation, Safety, Customer Care, Telecom Networking Legal, Risk Management, Communications & HR, Business Technology	Overhead costs charged directly.	453,905	100.00%	0
TOTAL			$74,896,284	75.32%	$24,539,298

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	**Total Nonutility Subsidiaries**			$0		$0
5	**Total Nonutility Subsidiaries Revenues**			$0		
6						
7						
8						
9	**Utility Subsidiaries**					
10						
11	**Total Utility Subsidiaries**			$0		$0
12	Canadian-Montana Pipeline Corporation	Natural gas pipeline	Contract rate	$145,443		
13	Havre Pipeline Company, LLC	Natural gas gathering	Tariffed rate	5,289,878		
14	**Total Utility Subsidiaries Revenues**			$5,435,321		
15	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
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	14.0%	$500,400
14						
15	**Total Utility Subsidiaries**			$500,400		$500,400
16	**Total Utility Subsidiaries Expenses**			$3,610,287		
17	**TOTAL AFFILIATE TRANSACTIONS**			$500,400		$500,400

Sch. 8	MONTANA UTILITY INCOME STATEMENT - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 830,472	$ -	$ 830,472	$ 781,763	6.23%
3						
4	**Total Operating Revenues**	830,472	-	830,472	781,763	6.23%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	729,765	-	729,765	695,207	4.97%
9	402 Maintenance Expense	26,753	-	26,753	35,757	-25.18%
10	403 Depreciation Expense	40,899	-	40,899	41,462	-1.36%
11	407.3 Regulatory Debits	-	-	-	-	-
12	408.1 Taxes Other Than Income Taxes	59,048	-	59,048	54,979	7.40%
13	409.1 Income Taxes-Federal			-	-	-
14	-Other			-	-	-
15	410.1 Deferred Income Taxes-Dr.	(5,884)	-	(5,884)	(15,253)	61.42%
16	411.1 Deferred Income Taxes-Cr.	-	-	-	-	-
17						
18	**Total Operating Expenses**	850,581	-	850,581	812,152	4.73%
19	**NET OPERATING INCOME**	$ (20,109)	$ -	$ (20,109)	$ (30,389)	33.83%

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.

Sch. 9	MONTANA REVENUES - PROPANE					
	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	$ 509,153	$ -	$ 509,153	$ 502,361	1.35%
5	442 Commercial & Industrial-Small	321,319	-	$ 321,319	279,402	15.00%
6						
7	**Total Sales to Ultimate Consumers**	830,472	-	830,472	781,763	6.23%
8	447 Sales for Resale					
9						
10	**Total Sales of Propane**	830,472	-	830,472	781,763	6.23%
11	449.1 Provision for Rate Refunds					
12						
13	**Total Revenue Net of Rate Refunds**	830,472	-	830,472	781,763	6.23%
14						
15	**Other Operating Revenues**					
16						
17	**Total Other Operating Revenue**	-	-	-	-	-
18	**TOTAL OPERATING REVENUE**	$ 830,472	$ -	$ 830,472	$ 781,763	6.23%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Supply Expenses**					
2	**Other Propane Supply Expense-Operation**					
3	804 Purchases	$ -	$ -	$ -	$ -	-
4	805 Other Propane Purchases	16,021	-	16,021	9,883	62.11%
5	807 Purchased Propane Expense			-	-	-
6	808 Propane Withdrawn from Storage	591,168	-	591,168	573,746	3.04%
7	809 Propane Delivered to Storage	-	-	-	-	-
8	**Total Supply Expenses**	607,189	-	607,189	583,629	4.04%
9	**Storage Expenses**					
10	**Other Storage-Operation**					
11	840 Operation Supervision & Engineering	-	-	-	-	-
12	841 Operation Labor & Expenses	-	-	-	-	-
13	842 Rents	16,685	-	16,685	11,819	41.17%
14	**Total Operation-Other Storage**	16,685	-	16,685	11,819	41.17%
15						
16	**Other Storage-Maintenance**					
17	847 Maintenance Storage Expenses	-	-	-	-	-
18	**Total Maintenance-Other Storage**	-	-	-	-	-
19	**Total Storage Expenses**	16,685	-	16,685	11,819	41.17%
20	**Distribution Expenses**					
21	**Distribution-Operation**					
22	870 Supervision & Engineering	-	-	-	-	-
23	874 Mains & Service	12,944	-	12,944	15,301	-15.40%
24	878 Meter & House Regulators	46,542	-	46,542	36,595	27.18%
25	879 Customer Installation	6,669	-	6,669	10,452	-36.20%
26	880 Other	1,697	-	1,697	1,376	23.32%
27	**Total Operation-Distribution**	67,852	-	67,852	63,724	6.48%
28	**Distribution-Maintenance**					
29	885 Maintenance Superv. & Eng.	-	-	-	-	-
30	887 Maintenance of Mains	23,598	-	23,598	30,646	-23.00%
31	892 Maint. of Services	893		893	3,705	-75.89%
32	893 Maint. of Meters & House Regulators	2,048	-	2,048	1,372	49.34%
33	894 Maintenance of Other Equipment	213	-	213	34	>300.00%
34	**Total Maintenance-Distribution**	26,752	-	26,752	35,757	-25.18%
35	**Total Distribution Expenses**	94,604	-	94,604	99,481	-4.90%
36						
37	**Customer Accounts Expenses**					
38	**Customer Accounts-Operation**					
39	901 Supervision	-	-	-	-	-
40	902 Meter Reading	915	-	915	1,292	-29.22%
41	903 Customer Records & Collection Expense	673	-	673	-	-
42	**Total Customer Accounts Expenses**	1,588	-	1,588	1,292	22.87%
43	**Administrative & General Expenses**					
44	**Admin. & General - Operation**					
45	920 Salaries	702	-	702	704	-0.34%
46	921 Office Supplies & Expenses	14	-	14	20	-29.63%
47	923 Outside Services	35,736	-	35,736	34,020	5.04%
48	925 Injuries & Damages	-	-	-	-	-
49	926 Employee Pensions and Benefits	-	-	-	-	-
50	928 Regulatory Commission Expense	-	-	-	-	-
51	**Total Operation-Admin. & General**	36,452	-	36,452	34,744	4.92%
52	**Admin. & General - Maintenance**					
53	935 General Plant	-	-	-	-	-
54	**Total Admin. & General Expenses**	36,452	-	36,452	34,744	4.92%
55						
56	**TOTAL OPER. & MAINT. EXPENSES**	$ 756,518	$ -	$ 756,518	$ 730,965	3.50%

Sch. 11	MONTANA TAXES OTHER THAN INCOME - PROPANE			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$2,813	$3,338	-15.72%
3	Real Estate & Personal Property	54,240	49,764	8.99%
4	Consumer Counsel	249	235	6.02%
5	Public Service Commission	1,744	1,642	6.21%
6	Vehicle Use Tax	1	-	-
7				
8	**TOTAL TAXES OTHER THAN INCOME**	$59,048	$54,979	7.40%

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

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

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

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

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

Sch. 14	Pension Costs 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: ____________		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	Change in Benefit Obligation			
7	Benefit obligation at beginning of year	$ 510,163,556	$ 545,833,926	-6.54%
8	Service cost	9,792,283	12,287,637	-20.31%
9	Interest cost	23,633,207	20,553,581	14.98%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	97,569,854	(49,399,148)	297.51%
13	Acquisition	-	-	-
14	Benefits paid	(19,791,487)	(19,112,440)	-3.55%
15	Benefit obligation at end of year	$ 621,367,413	$ 510,163,556	21.80%
16	Change in Plan Assets			
17	Fair value of plan assets at beginning of year	$ 459,232,101	$ 419,255,762	9.54%
18	Actual return on plan assets	47,571,410	48,588,779	-2.09%
19	Acquisition	-	-	-
20	Employer contribution	9,000,000	10,500,000	-14.29%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(19,791,487)	(19,112,440)	-3.55%
23	Fair value of plan assets at end of year	$ 496,012,024	$ 459,232,101	8.01%
24	Funded Status	$ (125,355,389)	$ (50,931,455)	-146.13%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (125,355,389)	$ (50,931,455)	-146.13%
30	Weighted-average Assumptions as of Year End			
31	Discount rate	3.90%	4.75%	-17.89%
32	Expected return on plan assets	5.80%	7.00%	-17.14%
33	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% Non-Union	
34	Components of Net Periodic Benefit Costs			
35	Service cost	$ 9,792,283	$ 12,287,637	-20.31%
36	Interest cost	23,633,207	20,553,581	14.98%
37	Expected return on plan assets	(26,316,885)	(28,886,294)	8.89%
38	Amortization of prior service cost	246,361	246,361	
39	Recognized net actuarial gain	2,117,774	11,138,542	-80.99%
40	Net periodic benefit cost (SEC Basis)	$ 9,472,740	$ 15,339,827	-146.13%
41	Montana Intrastate Costs: (MPSC Regulatory Basis)			
42	Pension Costs	$ 9,000,000	$ 10,500,000	-14.29%
43	Pension Costs Capitalized	1,822,578	2,161,868	-15.69%
44	Accumulated Pension Asset (Liability) at Year End	$ (125,355,389)	$ (50,931,455)	-146.13%
45	Number of Company Employees:			
46	Covered by the Plan	3,041	3,061	-0.65%
47	Not Covered by the Plan 2/	441	342	28.95%
48	Active	860	899	-4.34%
49	Retired	1,432	1,394	2.73%
50	Deferred Vested Terminated	749	768	-2.47%

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

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

Sch. 14a	Pension Costs 1/			
1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? N/A		
5				
	Item	Current Year	Last Year	% Change
6	**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	$ 312,279,277	$ 253,146,989	-18.94%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 8,715,756	$ 7,790,683	11.87%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 329,680,178	$ 312,279,277	5.57%
24	**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	$ 6,258,247	$ 5,480,587	14.19%
44	401(k) Plan Defined Contribution Costs Capitalized	1,267,349	1,128,410	12.31%
45	Accumulated Pension Asset (Liability) at Year End		Not Applicable	
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,587	1,470	7.96%
48	Not Covered by the Plan			
49	Active - Participating	1,537	1,434	7.18%
50	Retired			
51	Vested Former Employees, Retirees and Active-	259	477	-45.70%
52	Noncontributing			
	2/ This plan covers all NorthWestern Corporation employees.			
	3/ Represents total company 401(k) plan participants.			

Sch. 15	Other Post Employment Benefits (OPEBS)			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2012.9.94			
4	Order number: 7249e			
5	Amount recovered through rates	($101,920)	$177,804	-157.32%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	3.20%	3.75%	-14.67%
8	Expected return on plan assets	5.80%	7.00%	-17.14%
9	Medical Cost Inflation Rate 3/	8.0%,4.5%:14	8.25%,4.5%:15	
10	Actuarial Cost Method	Projected Unit Credit Actuarial, Cost Method Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	**Describe any Changes to the Benefit Plan:**			
16				

1/ Obtained from NorthWestern Energy-Montana's 2014 FASB 106 Valuation. Assumptions and data are as of December 31, 2014.

2/ Obtained from NorthWestern Energy-Montana's 2013 FASB 106 Valuation. Assumptions and data are as of December 31, 2013.

3/ First Year, Ultimate, Years to Reach Ultimate.

Sch. 15a	Post Employment Benefits (OPEBS) (continued)			
	Item	Current Year	Last Year	% Change
1	**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	$20,677,119	$23,181,823	-10.80%
10	Service cost	374,530	434,332	-13.77%
11	Interest Cost	743,834	616,759	20.60%
12	Plan participants' contributions	576,792	775,242	-25.60%
13	Amendments	-	-	-
14	Actuarial loss/(gain)	896,216	(2,304,870)	138.88%
15	Acquisition	-	-	-
16	Benefits paid	(2,301,355)	(2,026,167)	-13.58%
17	Benefit obligation at end of year	$20,967,136	$20,677,119	1.40%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$18,183,195	$15,893,406	14.41%
20	Actual return on plan assets	1,390,832	2,661,840	-47.75%
21	Acquisition	-	-	-
22	Employer contribution	190,853	878,874	-78.28%
23	Plan participants' contributions	576,792	775,242	-25.60%
24	Benefits paid	(2,301,355)	(2,026,167)	-13.58%
25	Fair value of plan assets at end of year	$18,040,317	$18,183,195	-0.79%
26	**Funded Status**	($2,926,819)	($2,493,924)	-17.36%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	($2,926,819)	($2,493,924)	-17.36%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$374,530	$434,332	-13.77%
33	Interest cost	743,834	616,759	20.60%
34	Expected return on plan assets	(980,569)	(1,019,000)	3.77%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,148,915)	(2,148,915)	
37	Recognized net actuarial loss/(gain)	347,876	733,305	-52.56%
38	Net periodic benefit cost	($1,663,244)	($1,383,519)	-20.22%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	190,853	878,875	-78.28%
43	TOTAL	$190,853	$878,875	-78.28%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(101,920)	177,804	-157.32%
47	TOTAL	($101,920)	$177,804	-157.32%
48	**Montana Intrastate Costs:**			
49	Pension Costs	($101,920)	$177,804	-157.32%
50	Pension Costs Capitalized	(20,640)	36,608	-156.38%
51	Accumulated Pension Asset (Liability) at Year End	(2,926,819)	(2,493,924)	-17.36%
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,913	1,971	-2.94%
54	Not Covered by the Plan	92	148	-37.84%
55	Active	887	926	-4.21%
56	Retired	932	950	-1.89%
57	Spouses/Dependants covered by the Plan	94	95	-1.05%

4/ There is approximately an additional $9,037,879 and $9,406,969 in other company OPEBS liabilities outstanding at December 31, 2014 and 2013, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

SCHEDULE 16

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

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Michael R. Cashell Vice President, Transmission	204,827	91,019 A	32,663 B 109,722 C 5,980 D 257,794 E	702,005	379,396	85%
2	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	217,201	95,787 A	21,482 B 117,859 C 244,870 E 37 F	697,236	390,824	78%
3	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	239,493	106,423 A	48,610 B 128,277 C 36,563 E	559,366	449,228	25%
4	John D. Hines Vice President, Supply	204,827	91,019 A	19,158 B 109,722 C 3,609 D 103,640 E 37 F	532,012	377,938	41%
5	William T. Rhoads General Manager, Generation	177,329	44,688 A	24,073 B 34,727 C 6,946 D 222,800 E 459 F	511,022	265,549	92%
6	Michael L. Nieman Chief Audit and Compliance Officer	204,257	64,342 A	49,022 B 49,982 C 39,678 E 37 F	407,318	335,650	21%
7	Daniel L. Rausch Treasurer	193,629	61,151 A	46,716 B 47,031 C 6,785 D 28,623 E	383,935	327,888	17%
8	Jeanne M. Vold Business Technology Officer	176,341	55,691 A	25,660 B 42,853 C 20,177 E	320,722	304,227	5%
9	Wayne M. Hitt Director Tax	159,191	39,798 A	38,076 B 31,852 C 10,506 E	279,423	N/A	
10	Timothy P. Olson Corporate Counsel & Corp Secretary	160,112	40,483 A	41,088 B 31,047 C	272,730	N/A	

EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	1/ Bonuses include the following:						
2							
3	A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2014						
4	Annual Incentive Compensation Plan. Amounts were earned in 2014 and paid in the first quarter of 2015.						
5	Based on company performance against plan, the incentive plan was funded at 125% of target.						
6	Individual awards varied from the funded level based on individual performance.						
7							
8	2/ All Other Compensation for named employees consists of the following:						
9							
10	B> Employer contributions to benefits - medical, dental, vision, employee assistance program,						
11	group term life, Health Savings Account, wellness incentive, 401(k) match, and non-elective						
12	401(k) contribution.						
13							
14	C> Values reflect the grant date fair value for performance stock awards.						
15							
16	D> Vacation sold back during the year.						
17							
18	E> Change in pension value over previous year. The present value of accumulated benefits was calculated						
19	assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed						
20	payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements						
21	in our Annual Report on Form 10-K for the year ended December 31, 2014.						
22							
23	F> Noncash taxable award and tax gross-up on award.						
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							

SCHEDULE 17

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

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Robert C. Rowe President & Chief Executive Officer	556,924	561,389 A	22,114 B 1,098,234 C 104,139 D 41 E	2,342,841	1,724,898	36%
2	Brian B. Bird Vice President & Chief Financial Officer	365,351	230,175 A	49,005 B 422,840 C 32,002 D	1,099,373	871,971	26%
3	Heather H. Grahame Vice President & General Counsel	332,462	188,509 A	46,592 B 278,547 C 37 E	846,147	692,658	22%
4	Curtis T. Pohl Vice President, Distribution Operations	261,754	131,927 A	52,842 B 206,470 C 64,786 D 9,237 F	727,016	558,633	30%
5	Kendall Kliewer Vice President & Controller	241,478	106,494 A	46,366 B 131,043 C 36,373 D	561,754	458,055	23%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2014 Annual Incentive Compensation Plan. Amounts were earned in 2014 and paid in the first quarter of 2015. Based on company performance against plan, the incentive plan was funded at 125% of target.

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

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

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

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2014.

E> Noncash taxable award and tax gross-up on award.

F> Vacation sold back during the year.

Sch. 18	BALANCE SHEET 1/				
	Account Title	This Year	Last Year	Variance	% Change
1	**Assets and Other Debits**				
2	**Utility Plant**				
3	101 Plant in Service	$4,612,121,385	$3,974,701,127	$637,420,258	16.04%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	-	0.00%
5	105 Plant Held for Future Use	3,558,413	3,560,555	(2,142)	-0.06%
6	107 Construction Work in Progress	213,126,467	97,044,707	$116,081,760	119.62%
7	108 Accumulated Depreciation Reserve	(1,690,819,946)	(1,616,152,234)	($74,667,712)	4.62%
8	108.1 Accumulated Depreciation - Capital Leases	(17,089,022)	(15,078,542)	($2,010,480)	13.33%
9	111 Accumulated Amortization & Depletion Reserves	(37,112,782)	(27,467,302)	($9,645,480)	35.12%
10	114 Electric Plant Acquisition Adjustments	350,132,657	-	350,132,657	-
11	115 Accumulated Amortization-Electric Plant Acq. Adj.	(937,002)	-	(937,002)	-
12	116 Utility Plant Adjustments	355,128,500	355,128,500	-	0.00%
13	117 Gas Stored Underground-Noncurrent	32,135,879	32,120,387	15,492	0.05%
14	Total Utility Plant	3,860,454,086	2,844,066,735	1,016,387,351	35.74%
15	**Other Property and Investments**				
16	121 Nonutility Property	6,749,606	6,749,606	-	0.00%
17	122 Accumulated Depr. & Amort.-Nonutility Property	(1,154,851)	(819,346)	(335,505)	40.95%
18	123.1 Investments in Assoc Companies and Subsidiaries	(140,450,323)	(141,594,938)	1,144,615	-0.81%
19	124 Other Investments	39,899,904	16,784,220	23,115,684	137.72%
20	128 Miscellaneous Special Funds	16,787,692	-	16,787,692	-
21	LT Portion of Derivative Assets - Hedges	-	-	-	-
22	Total Other Property & Investments	(78,167,972)	(118,880,458)	40,712,486	-34.25%
23	**Current and Accrued Assets**				
24	131 Cash	12,841,079	10,387,435	2,453,644	23.62%
25	134 Other Special Deposits	10,528,068	4,169,290	6,358,778	152.51%
26	135 Working Funds	42,575	40,125	2,450	6.11%
27	136 Temporary Cash Investments	-	-	-	-
28	141 Notes Receivable	-	-	-	-
29	142 Customer Accounts Receivable	83,662,524	88,584,019	(4,921,495)	-5.56%
30	143 Other Accounts Receivable	16,550,278	16,564,952	(14,674)	-0.09%
31	144 Accumulated Provision for Uncollectible Accounts	(4,301,616)	(4,451,666)	150,050	-3.37%
32	145 Notes Receivable-Associated Companies	-	-	-	-
33	146 Accounts Receivable-Associated Companies	344,565	148,135	196,430	132.60%
34	151 Fuel Stock	7,630,351	8,460,264	(829,913)	-9.81%
35	154 Plant Materials and Operating Supplies	29,082,484	26,791,073	2,291,411	8.55%
36	164 Gas Stored - Current	16,360,518	18,351,754	(1,991,236)	-10.85%
37	165 Prepayments	13,818,312	13,775,768	42,544	0.31%
38	171 Interest and Dividends Receivable	-	-	-	-
40	172 Rents Receivable	204,569	80,272	124,297	154.84%
41	173 Accrued Utility Revenues	70,315,316	74,345,656	(4,030,340)	-5.42%
42	174 Miscellaneous Current & Accrued Assets	30,019,535	877	30,018,658	>300.00%
43	175 Derivative Instrument Assets (175)	-	-	-	100.00%
44	(Less) Long-Term Portion of Derivative Instrument Assets	-	-	-	-
45	176 LT Portion of Derivative Assets - Hedges	-	-	-	-
46	(less) LT Portion of Derivative Assets - Hedges	-	-	-	-
47	Total Current & Accrued Assets	287,098,558	257,247,954	29,850,604	11.60%
48	**Deferred Debits**				
49	181 Unamortized Debt Expense	13,041,834	13,614,516	(572,682)	-4.21%
50	182 Regulatory Assets	463,907,330	324,402,612	139,504,718	43.00%
51	183 Preliminary Survey and Investigation Charges	1,185,617	1,185,617	-	0.00%
52	184 Clearing Accounts	900	30,449	(29,549)	-97.04%
53	185 Temporary Facilities	-	-	-	-
54	186 Miscellaneous Deferred Debits	530,880	876,649	(345,769)	-39.44%
55	189 Unamortized Loss on Reacquired Debt	12,151,208	13,918,710	(1,767,502)	-12.70%
56	190 Accumulated Deferred Income Taxes	186,187,313	125,015,983	61,171,330	48.93%
57	191 Unrecovered Purchased Gas Costs	25,520,064	16,260,432	9,259,632	56.95%
58	Total Deferred Debits	702,525,146	495,304,968	207,220,178	41.84%
59	TOTAL ASSETS and OTHER DEBITS	$ 4,771,909,818	$ 3,477,739,199	$ 1,294,170,619	37.21%

Sch. 18 cont. **BALANCE SHEET 1/**

Line	Account Title	This Year	Last Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 505,226	$ 423,405	$ 81,821	19.32%
4	204 Preferred Stock Issued	-	-	-	-
5	207 Premium on Capital Stock	-	-	-	-
6	211 Miscellaneous Paid-In Capital	1,313,844,035	910,184,562	403,659,473	44.35%
7	213 Discount on Capital Stock	-	-	-	-
8	214 Capital Stock Expense	-	-	-	-
9	215 Appropriated Retained Earnings	-	-	-	-
10	216 Unappropriated Retained Earnings	264,757,908	209,090,660	55,667,248	26.62%
12	217 Reacquired Capital Stock	(92,558,283)	(91,744,257)	(814,026)	0.89%
13	219 Accumulated Other Comprehensive Income	(8,765,944)	2,716,002	(11,481,946)	>-300.00%
14	**Total Proprietary Capital**	1,477,782,942	1,030,670,372	447,112,570	43.38%
15	**Long Term Debt**				
16	221 Bonds	1,635,205,000	1,155,205,000	480,000,000	41.55%
17	223 Advances in Associated Companies	-	-	-	-
18	224 Other Long Term Debt	26,976,900	-	26,976,900	-
19	226 (Less) Unamortized Discount on Long Term Debt-Debit	83,438	107,538	(24,100)	-22.41%
20	**Total Long Term Debt**	1,662,098,462	1,155,097,462	507,001,000	43.89%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	28,162,445	29,894,898	(1,732,453)	-5.80%
23	228.1 Accumulated Provision for Property Insurance	-	-	-	-
24	228.2 Accumulated Provision for Injuries and Damages	9,061,051	8,748,808	312,243	3.57%
25	228.3 Accumulated Provision for Pensions and Benefits	20,244,171	19,808,834	435,337	2.20%
26	228.4 Accumulated Miscellaneous Operating Provisions	164,953,264	164,641,920	311,344	0.19%
27	229 Accumulated Provision for Rate Refunds	34,280,250	27,235,028	7,045,222	25.87%
28	230 Asset Retirement Obligations	21,435,223	18,803,779	2,631,444	13.99%
29	**Total Other Noncurrent Liabilities**	278,136,404	269,133,267	9,003,137	3.35%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	267,840,079	140,949,554	126,890,525	90.03%
32	232 Accounts Payable	90,659,542	97,936,435	(7,276,893)	-7.43%
33	233 Notes Payable to Associated Companies	-	-	-	-
34	234 Accounts Payable to Associated Companies	1,466,006	1,420,295	45,711	3.22%
35	235 Customer Deposits	6,621,535	10,847,568	(4,226,033)	-38.96%
36	236 Taxes Accrued	39,264,570	41,116,000	(1,851,430)	-4.50%
37	237 Interest Accrued	19,734,213	18,038,039	1,696,174	9.40%
39	238 Dividends Declared	-	-	-	-
40	241 Tax Collections Payable	1,892,527	1,467,454	425,073	28.97%
41	242 Miscellaneous Current and Accrued Liabilities	63,800,309	57,359,786	6,440,523	11.23%
42	243 Obligations Under Capital Leases-Current	1,729,507	1,662,235	67,272	4.05%
43	244 Derivative Instrument Liabilities	-	-	-	-
44	245 Derivative Instrument Liabilities - Hedges	18,310,043	-	18,310,043	-
45	**Total Current and Accrued Liabilities**	511,318,331	370,797,366	140,520,965	37.90%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	30,000,627	27,370,414	2,630,213	9.61%
48	253 Other Deferred Credits	171,200,388	94,739,483	76,460,905	80.71%
49	254 Regulatory Liabilities	26,470,224	22,852,872	3,617,352	15.83%
50	255 Accumulated Deferred Investment Tax Credits	588,781	861,860	(273,079)	-31.68%
51	257 Unamortized Gain on Reacquired Debt	-	-	-	-
52	281-283 Accumulated Deferred Income Taxes	614,313,659	506,216,103	108,097,556	21.35%
53	**Total Deferred Credits**	842,573,679	652,040,732	190,532,947	29.22%
54	TOTAL LIABILITIES and OTHER CREDITS	$ 4,771,909,818	$ 3,477,739,199	$ 1,294,170,619	37.21%
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 FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 692,600 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. The preparation of financial statements in conformity with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. Events occurring subsequent to December 31, 2014, have been evaluated as to their potential impact to the Financial Statements through the date of issuance. Our November 2014 acquisition of hydro generating assets is included in the results of operations for the year ended December 31, 2014, and impacts the comparability of the current year financial statements to prior years. For a further discussion of this acquisition, see Note 3 - Hydro Transaction.

(2) Significant Accounting Policies

Financial Statement Presentation

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

- Earnings per share is not presented;
- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $351.7 million and $336.6 million as of December 31, 2014 and December 31, 2013, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes;
- Goodwill is reflected in the Balance Sheets as a utility plant adjustment of $355.1 million as of December 31, 2014 and December 31, 2013, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 9);
- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the Balance Sheets as a component of accumulated depreciation of $147.6 million for December 31, 2014 and December 31, 2013, respectively, in accordance with regulatory treatment as compared to plant for GAAP purposes;
- The current portion of gas stored underground is reflected in the Balance Sheets as current and accrued assets, as compared to inventory for GAAP purposes;
- Current and long-term debt is classified in the Balance Sheets as all long-term debt in accordance with regulatory treatment, while current and long-term debt are separately presented for GAAP reporting;

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

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

Use of Estimates

The preparation of financial statements in conformity with the regulatory basis of accounting requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, asset retirement obligations, uncollectible accounts, our QF liability, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electrical and natural gas services delivered to customers, but not yet billed at month-end.

Cash Equivalents

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

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $4.3 million and $4.5 million at December 31, 2014 and December 31, 2013, respectively. Unbilled revenues were $70.3 million and $74.3 million at December 31, 2014 and December 31, 2013, respectively.

Inventories

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

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

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980. Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

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

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

Derivative Financial Instruments

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

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

Utility Plant

Utility Plant is stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility plant are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in utility plant are assets under capital lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.0% and 8.1%, for Montana and South Dakota for 2014 and 2013, respectively. AFUDC capitalized totaled $10.8 million for the year ended December 31, 2014 and $8.2 million for the year ended December 31, 2013 for Montana and South Dakota combined.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from three to 50 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 2.9% and 3.2% for 2014 and 2013, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission our jointly owned plants at the end of the useful life. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in accumulated depreciation.

Income Taxes

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

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if there is precedent for recovering similar costs from customers in rates. Otherwise, we expense the costs. If an environmental cost is related to facilities we currently use, such as pollution control equipment, then we may capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost.

Business Combination

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

Accounting Standards Issued

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

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

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

Accounting Standards Adopted

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

(3) Hydro Transaction

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

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

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

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

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

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

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

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

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

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

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

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

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

(4) Regulatory Matters

South Dakota Electric Rate Filing

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

Dave Gates Generating Station at Mill Creek (DGGS)

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

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

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

Montana Electric Tracker Filings

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

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

Montana Lost Revenue Adjustment Mechanism

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

Based on the MPSC's October 2013 order, we have recognized $7.1 million of DSM lost revenues for each annual electric supply tracker period. However, since the 2012/2013 and 2013/2014 annual electric tracker filings are still subject to final approval, the MPSC may ultimately require us to refund a portion of the DSM lost revenues we have recognized since July 2012.

Montana Natural Gas Tracker Filings and Natural Gas Production Assets

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

In 2012 and 2013, we purchased natural gas production interests in northern Montana's Bear Paw Basin (Bear Paw). We are collecting the cost of service for natural gas produced from these assets, including a return on our investment, through our natural gas supply tracker on an interim basis. As a result, we do not expect to file an application with the MPSC to place these assets in natural gas rate base until our next natural gas rate case. We are recognizing Bear Paw related revenue based on the precedent established by the MPSC's approval of Battle Creek in the fourth quarter of 2012. Since acquisition, we have recognized approximately $38.5 million of revenue, a portion of which may be subject to refund.

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

(5) Equity Investments

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

	December 31,			
	2014		2013	
Colstrip Unit 4 Basis Adjustment	$	(156,806)	$	(159,895)
Havre Pipeline Company, LLC		12,912		14,576
NorthWestern Services, LLC		1,883		1,876
Risk Partners Assurance, Ltd.		1,561		1,848
Total Investments in Subsidiary Companies	$	(140,450)	$	(141,595)

(6) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to the customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. These regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

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

Pension and Employee Related Benefits

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

Montana Distribution System Infrastructure Project (DSIP)

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

Environmental clean-up

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

Income Taxes

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

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

The MPSC has authorized recovery in the property tax tracker of approximately 60% of the estimated increase as compared with the related amount included in rates during our last rate case.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

Unbilled Revenue

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

(7) Utility Plant

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

	December 31,	
	2014	2013
Land and improvements	$ 137,098	$ 128,886
Building and improvements	345,451	236,668
Storage, distribution, and transmission	2,769,946	2,641,121
Generation	1,483,137	757,698
Construction work in process	213,126	97,045
Other equipment	270,390	253,891
	5,219,148	4,115,516
Less accumulated depreciation	(1,745,959)	(1,658,698)
	$ 3,473,189	$ 2,456,818

In 2014, we acquired hydro generating assets which resulted in an increase of approximately $870 million in utility plant. We recorded the plant assets at original cost, less accumulated depreciation with an acquisition adjustment in accordance with FERC rules. Utility plant under capital lease were $23.4 million and $25.6 million as of December 31, 2014 and 2013, respectively, which included $23.1 million and $25.1 million as of December 31, 2014 and 2013, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as an obligation under capital lease.

Jointly Owned Electric Generating Plant

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

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

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
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
December 31, 2013				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 61,186	$ 57,633	$ 46,003	$ 290,163
Accumulated depreciation	45,792	29,841	36,076	70,072

(8) Asset Retirement Obligations

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

Our AROs relate to the reclamation and removal costs at our jointly-owned coal-fired generation facilities, Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, and our obligation to plug and abandon oil and gas wells at the end of their life. The following table presents the change in our gross conditional ARO (in thousands):

	December 31,	
	2014	2013
Liability at January 1,	$ 20,886	$ 9,283
Accretion expense	1,073	745
Liabilities incurred	552	8,829
Liabilities settled	(85)	(27)
Revisions to cash flows	(991)	2,056
Liability at December 31,	$ 21,435	$ 20,886

In addition, we have identified removal liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time. We also identified AROs associated with our Hydro Transaction; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the financial statements

We collect removal costs in rates for certain transmission and distribution assets that do not have associated AROs. Generally, the accrual of future non-ARO removal obligations is not required; however, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates.

(9) Utility Plant Adjustments

We completed our annual utility plant adjustments impairment test as of April 1, 2014 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

(10) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

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

Objectives and Strategies for Using Derivatives

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

In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale; cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the NPNS exception to our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no amounts recorded in the Financial Statements at December 31, 2014 and 2013. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Credit Risk

Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We limit credit risk in our commodity and interest rate derivative activities by assessing the creditworthiness of potential counterparties before entering into transactions and continuing to evaluate their creditworthiness on an ongoing basis.

We are exposed to credit risk through buying and selling electricity and natural gas to serve customers. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties. We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements - standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements - standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements - standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements - standardized power sales contracts in the electric industry.

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

Interest Rate Swaps Designated as Cash Flow Hedges

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

Amounts are reclassified from AOCI into interest on long-term debt during the periods in which the hedged interest payments occur. The following table shows the effect of the interest rate swaps terminated in November 2014 and interest rate swaps previously terminated on the Financial Statements (in thousands):

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

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

(11) Fair Value Measurements

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

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

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

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

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

December 31, 2014	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Other special	$ 10,528	$ —	$ —	$ —	$ 10,528
Rabbi trust investments	21,594	—	—	—	21,594
Total	$ 32,122	$ —	$ —	$ —	$ 32,122
December 31, 2013					
Other special deposits	$ 4,169	$ —	$ —	$ —	$ 4,169
Rabbi trust investments	16,477	—	—	—	16,477
Total	$ 20,646	$ —	$ —	$ —	$ 20,646

Other special deposits represent amounts held in money market mutual funds. Rabbi trust assets represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets.

Financial Instruments

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

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

Notes payable consist of commercial paper and are not included in the table above as carrying value approximates fair value. The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

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

(12) Notes Payable and Credit Arrangements

Notes Payable

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

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

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

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

In the fourth quarter of 2014, we increased the size of our commercial paper program from $250 million to $340 million. Under the program we may issue unsecured commercial paper notes on a private placement basis to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Commercial paper issuances are supported by available capacity under our unsecured revolving credit facility.

Unsecured Revolving Line of Credit

In the fourth quarter of 2014, we exercised the accordion feature under our $300 million unsecured revolving credit facility to increase the size to $350 million. The facility does not amortize and is scheduled to expire on November 5, 2018. The facility bears interest at the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%, or a base rate, plus a margin of 0.0% to 0.75%. A total of eight banks participate in the facility, with no one bank providing more than 21% of the total availability. There were no direct borrowings or letters of credit outstanding as of December 31, 2014. Commitment fees for the unsecured revolving line of credit were $0.4 million and $0.5 million for the years ended December 31, 2014 and 2013, respectively.

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

Bridge Facility

In November 2013, in connection with the Hydro Transaction, we entered into a $900 million 364-day senior bridge credit facility. The bridge facility was not drawn upon and cancelled in November 2014.

(13) Long-Term Debt

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

	Due	December 31, 2014	2013
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	—
Montana—6.04%	2016	150,000	150,000
Montana—6.34%	2019	250,000	250,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	—
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
Other Long Term Debt:			
New Market Tax Credit Financing—1.146%	2046	26,977	—
Discount on Notes and Bonds	—	(83)	(108)
		$ 1,662,099	$ 1,155,097

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

In December 2014, we issued $30 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 4.22% maturing in 2044. The bonds are secured by our electric and natural gas assets in South Dakota and were issued in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended. Proceeds were used to fund a portion of our investment growth opportunities.

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

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

Other Long-Term Debt

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

Maturities of Long-Term Debt

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

(14) Related Party Transactions

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

	December 31, 2014	December 31, 2013
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 327	$ 130
Risk Partners Assurance, Ltd.	18	18
	$ 345	$ 148
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	$ 1,466	$ 1,420

(15) Income Taxes

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

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

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

Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas and electric costs which are deferred for book purposes but expensed currently for tax purposes, and NOL carry forwards. We have elected under Internal Revenue Code 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

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

	December 31,	
	2014	2013
Pension / postretirement benefits	$ 51,817	$ 20,522
NOL carryforward	42,787	16,758
Unbilled revenue	19,863	18,136
Compensation accruals	17,315	10,409
Customer advances	11,817	10,781
AMT credit carryforward	10,357	10,357
Environmental liability	8,968	9,026
Production tax credit	6,452	3,171
Interest rate hedges	6,251	—
QF obligations	2,162	2,066
Reserves and accruals	2,102	12,097
Property taxes	879	794
Regulatory liabilities	975	659
Regulatory assets	—	7,248
Other, net	4,442	2,992
Deferred Tax Asset	**186,187**	**125,016**
Excess tax depreciation	(351,823)	(304,402)
Goodwill amortization	(137,090)	(122,798)
Flow through depreciation	(103,677)	(79,016)
Regulatory assets	(21,394)	—
Reserves and accruals	(330)	—
Deferred Tax Liability	**(614,314)**	**(506,216)**
Deferred Tax Liability, net	**$ (428,127)**	**$ (381,200)**

At December 31, 2014 we estimate our total federal NOL carryforward to be approximately $351 million prior to consideration of unrecognized tax benefits. If unused, our federal NOL carryforwards will expire as follows: $16.3 million in 2025; $95.5 million in 2028; $23.8 million in 2029; $127.5 million in 2031; $13.3 million in 2033 and $74.9 million in 2034. We estimate our state NOL carryforward as of December 31, 2014 is approximately $264.0 million. If unused, our state NOL carryforwards will expire as follows: $74.0 million in 2015; $18.6 million in 2016; $101.2 million in 2018; $10.5 million in 2020 and $59.7 million in 2021. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

Uncertain Tax Positions

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

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

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

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. As discussed above, during the year ended December 31, 2014, we released approximately $0.4 million of accrued interest in the Statements of Income. As of December 31, 2014, we do not have any amounts accrued in the Balance Sheets. During the year ended December 31, 2013, we recognized approximately $0.4 million of interest in the Statements of Income. As of December 31, 2013, we had $0.4 million of interest accrued in the Balance Sheets.

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

(16) Other Comprehensive Income (Loss)

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

	December 31,					
	2014			2013		
	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit	Net-of-Tax Amount
Foreign currency translation adjustment	$ 265	$ —	$ 265	$ 166	—	$ 166
Reclassification of net gains on derivative instruments	(1,110)	426	(684)	(1,188)	458	(730)
Realized loss on cash flow hedging derivatives	(18,388)	7,243	(11,145)	—	—	—
Pension and postretirement medical liability adjustment	134	(52)	82	1,568	(605)	963
Other comprehensive income (loss)	$ (19,099)	$ 7,617	$ (11,482)	$ 546	$ (147)	$ 399

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

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

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

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

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

(17) Operating Leases

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

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

Lease and rental expense incurred was $2.2 million and $2.0 million for the years ended December 31, 2014 and 2013, respectively.

(18) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our financial statements. See Note 6 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation and Funded Status

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

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

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

	Pension Benefits	
	December 31,	
	2014	2013
Projected benefit obligation	$ 688.4	$ 567.9
Accumulated benefit obligation	685.0	565.0
Fair value of plan assets	556.1	516.4

Net Periodic Cost (Credit)

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2014	2013	2014	2013
Components of Net Periodic Benefit Cost				
Service cost	$ 10,830	$ 13,465	$ 465	$ 541
Interest cost	26,147	22,719	859	877
Expected return on plan assets	(29,506)	(32,491)	(981)	(1,019)
Amortization of prior service cost (credit)	246	246	(1,998)	(1,998)
Recognized actuarial loss	2,118	11,648	348	1,271
Settlement loss recognized	—	—	690	—
Net Periodic Benefit Cost (Credit)	$ 9,835	$ 15,587	$ (617)	$ (328)

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

We estimate amortizations from regulatory assets into net periodic benefit cost during 2015 will be as follows (in thousands):

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

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2014 and 2013. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases.

Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

For 2014 and 2013, we set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The decrease in discount rate during 2014 increased our projected benefit obligation by approximately $73.6 million.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Based on the target asset allocation for our pension assets and future expectations for asset returns, we are keeping our long term rate of return on assets assumption at 5.80% for 2015.

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

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2014	2013	2014	2013
Discount rate	3.75-3.90 %	4.55-4.75 %	3.20-3.40 %	3.75-4.20 %
Expected rate of return on assets	5.80	7.00	5.80	7.00
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.58	3.58
Long-term rate of increase in compensation levels (union)	3.50	3.50	3.50	3.50

The postretirement benefit obligation is calculated assuming that health care costs increased by 8.25% in 2014 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually by 0.25% per year to an ultimate trend of 4.5% by the year 2029. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

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

- Each plan should be substantially fully invested as long-term cash holdings reduce long-term rates of return;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the overall funded status;

- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

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

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

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2014	2013	2014	2013
Domestic debt securities	55.0%	60.0%	40.0%	40.0%
International debt securities	5.0	5.0	—	—
Domestic equity securities	34.0	30.0	50.0	50.0
International equity securities	6.0	5.0	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2014	2013	2014	2013	2014	2013
Cash and cash equivalents	—%	—%	0.1%	0.1%	0.2%	1.8%
Domestic debt securities	56.0	58.6	65.6	64.7	37.2	38.6
International debt securities	4.4	4.9	4.5	4.9	—	0.3
Domestic equity securities	34.1	31.4	25.1	25.3	53.9	50.1
International equity securities	5.5	5.1	4.7	5.0	8.7	9.2
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

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

The fair value of our plan assets at December 31, 2014, by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 126	$ —	$ 126	$ —
Equity securities: (1)				
US small/mid cap growth	16,605	—	16,605	—
US small/mid cap value	15,264	—	15,264	—
US large cap growth	48,560	—	48,560	—
US large cap value	48,785	—	48,785	—
US large cap passive	54,775	—	54,775	—
Non-US core	22,634	—	22,634	—
Emerging markets	7,650	—	7,650	—
Fixed income securities:(2)				
US core	23,177	—	23,177	—
US passive	12,269	—	12,269	—
Long duration	41,451	—	41,451	—
Long duration investment grade	52,767	—	52,767	—
Long duration passive	41,475	—	41,475	—
Opportunistic	5,692	—	5,692	—
Non-US passive	24,504	—	24,504	—
Active long corporate	133,160	—	133,160	—
Participating group annuity contract	7,157	—	7,157	—
	$ 556,051	$ —	$ 556,051	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 44	$ —	$ 44	$ —
Equity securities: (1)			—	
US small/mid cap growth	752	—	752	—
US small/mid cap value	721	—	721	—
S&P 500 index	8,234	—	8,234	—
US large cap growth	6	—	6	—
US large cap value	6	—	6	—
US large cap passive	7	—	7	—
Non-US core	1,495	—	1,495	—
Emerging markets	72	—	72	—
Fixed income securities: (2)				
Passive bond market	1,992	—	1,992	—
US core	4,435	—	4,435	—
US passive	1	—	1	—
Long duration	5	—	5	—
Long duration investment grade	6	—	6	—
Long duration passive	5	—	5	—
Opportunistic	240	—	240	—
Non-US passive	3	—	3	—
Active long corporate	16	—	16	—
	$ 18,040	$ —	$ 18,040	$ —

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

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

(1) This category consists of active and passive managed equity funds, which are invested in multiple strategies to diversify risks and reduce volatility.
(2) This category consists of investment grade bonds of issuers from diverse industries, debt securities issued by international, national, state and local governments, and asset-backed securities. This includes both active and passive managed funds.

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

Cash Flows

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

Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, we estimate that our minimum annual required contribution for 2015 will be approximately $10.2 million. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

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

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

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

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

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the year ended December 31, 2014 and 2013 were $8.7 million and $7.8 million.

(19) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. In 2014, an additional 600,000 shares of common stock were authorized by the shareholders for issuance under the ECP. As of December 31, 2014, there were 1,124,798 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

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

Performance Share Awards

Performance share awards are granted annually under the ECP. With these awards, shares will vest if, at the end of the three-year performance period, we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. These awards contain both a market and performance based component. For our outstanding performance share awards which were granted in 2012 and 2013, the performance goals are independent of each other and equally weighted, and are based on two metrics: (i) cumulative net income and average return on equity; and (ii) total shareholder return (TSR) relative to a peer group. For the awards granted in 2014, our Board added an earnings per share metric and removed the net income metric, while retaining the average return on equity and TSR metrics.

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

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

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

A summary of nonvested shares as of and changes during the year ended December 31, 2014, are as follows:

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

We recognized compensation expense of $3.1 million and $2.4 million for the years ended December 31, 2014 and 2013, respectively, and a related income tax benefit of $0.1 million and $1.5 million, for the years ended December 31, 2014 and 2013, respectively. As of December 31, 2014, we had $3.6 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as other paid-in capital in our Balance Sheets. The cost is expected to be recognized over a weighted-average period of 2.0 years. The total fair value of shares vested was $2.1 million and $2.2 million for the years ended December 31, 2014 and 2013, respectively.

Retirement/Retention Restricted Share Awards

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

A summary of nonvested shares as of and changes during the year ended December 31, 2014, are as follows:

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

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years). During the years ended December 31, 2014 and 2013, DSUs issued to members of our Board totaled 26,460 and 33,837, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2014 and 2013 was approximately $2.3 million and $3.6 million, respectively.

(20) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,865,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 19 - Stock-Based Compensation.

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

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

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 23,630 and 34,552 during the years ended December 31, 2014 and 2013, respectively, and are reflected in reacquired capital stock. These shares were credited to reacquired capital stock based on their fair market value on the vesting date.

(21) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the Public Utility Regulatory Policies Act. The QFs require us to purchase minimum amounts of energy at prices ranging from $74 to $136 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.0 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $0.8 billion through 2029. The present value of the remaining QF liability is recorded in our Balance Sheets as an accumulated miscellaneous operating provision. The following summarizes the change in the QF liability (in thousands):

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

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

	Gross Obligation	Recoverable Amounts	Net
2015	$ 69,606	$ 56,598	$ 13,008
2016	71,598	57,188	14,410
2017	73,622	57,789	15,833
2018	75,688	58,401	17,287
2019	77,791	59,020	18,771
Thereafter	646,783	508,195	138,588
Total	$ 1,015,088	$ 797,191	$ 217,897

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 27 years. Costs incurred under these contracts were approximately $402.3 million and $379.4 million for the years ended December 31, 2014 and 2013, respectively. As of December 31, 2014, our commitments under these contracts are $206.5 million in 2015, $161.1 million in 2016, $134.9 million in 2017, $107.3 million in 2018, $103.5 million in 2019, and $922.7 million thereafter. These commitments are not reflected in our Financial Statements.

Hydroelectric License Commitments

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

Environmental Matters

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

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

Our liability for environmental remediation obligations is estimated to range between $26.4 million to $35.0 million, primarily for manufactured gas plants discussed below. As of December 31, 2014, we have a reserve of approximately $29.7 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. Over time, as costs become determinable, we may seek authorization to recover such costs in rates or seek insurance reimbursement as applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our financial position or results of operations.

Manufactured Gas Plants - Approximately $22.4 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies and implementing remedial actions at the Aberdeen site pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources (DENR). Our current reserve for remediation costs at this site is approximately $10.8 million, and we estimate that approximately $8.0 million of this amount will be incurred during the next five years.

We also own sites in North Platte, Kearney and Grand Island, Nebraska on which former manufactured gas facilities were located. We are currently working independently to fully characterize the nature and extent of potential impacts associated with these Nebraska sites. Our reserve estimate includes assumptions for site assessment and remedial action work. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

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

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

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

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

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

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

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

Water Intakes and Discharges - Section 316(b) of the Federal Clean Water Act (CWA) requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best technology available (BTA)" for minimizing environmental impacts. In May, 2014, the EPA issued a final rule applicable to facilities that withdraw at least 2 million gallons per day of cooling water from waters of the US and use at least 25 percent of the water exclusively for cooling purposes. The final rule gives options for meeting BTA, and provides a flexible compliance approach. In August 2014, EPA published the final rule establishing national requirements applicable to cooling water intake structures, which became effective in October, 2014. Under the rule, permits required for existing facilities will be developed by the individual states and additional capital and/or increased operating costs may be required to comply with future water permit requirements. Challenges to the final cooling water intake rule have been filed by industry groups and by environmental groups in various appellate courts.

In April 2013, the EPA proposed CWA regulations to address mercury, arsenic, lead, and selenium in water discharged from power plants. The proposed regulations include a variety of options for whether and how these different waste streams should be treated. The EPA is reviewing public comments on these options prior to enacting final regulations. Under the proposed approach, new requirements for existing power plants would be phased in between 2017 and 2022. The EPA is under a modified consent decree to take final action by September 30, 2015. The EPA estimates that over half of the existing power plants will not incur costs under any of the proposed options because many power plants already have the technology and procedures in place to meet the proposed pollution control standards; however, it is too early to determine whether the impacts of these rules will be material.

Clean Air Act Rules and Associated Emission Control Equipment Expenditures

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

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

In December 2011, the EPA issued a final rule relating to Mercury and Air Toxics Standards (MATS). Among other things, the MATS set stringent emission limits for acid gases, mercury, and other hazardous air pollutants from new and existing electric generating units. Facilities that are subject to the MATS must come into compliance by April 2015, unless a one year extension is granted on a case-by-case basis. In April 2014, the U.S. Court of Appeals for the D.C. Circuit upheld the MATS rule. The decision was appealed by 23 states and industry groups to the Supreme Court, and in November, 2014 the Court agreed to hear the case. Oral argument will likely be scheduled for the spring and the Supreme Court is expected to issue a ruling by June, 2015.

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to reduce emissions from electric generating units that interfere with the ability of downwind states to achieve ambient air quality standards. Under CSAPR, significant reductions in emissions of nitrogen oxide (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. Litigation of the remaining CSAPR lawsuits continues, with briefings and oral argument set for 2015.

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

In September 2012, a final Federal Implementation Plan for Montana was published in the Federal Register to address regional haze. As finalized, Colstrip Unit 4 does not have to improve removal efficiency for pollutants that contribute to regional haze. By 2018, Montana, or EPA, must develop a revised Plan that demonstrates reasonable progress toward eliminating man made emissions of visibility impairing pollutants, which could impact Colstrip Unit 4. In November 2012, PPL Montana, the operator of Colstrip, as well as environmental groups (National Parks Conservation Association, Montana Environmental Information Center, and Sierra Club) jointly filed a petition for review of the Federal Implementation Plan in the U.S. Court of Appeals for the Ninth Circuit. Montana Environmental Information Center and Sierra Club have challenged the EPA's decision not to require any emissions reductions from Colstrip Units 3 and 4. The Ninth Circuit held oral argument on the petition on May 16, 2014, but no decision has been issued and at this time, we cannot predict or determine the timing or outcome of this petition.

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

South Dakota. The South Dakota DENR determined that the Big Stone Plant, of which we have a 23.4% ownership, is subject to the BART requirements of the Regional Haze Rule. South Dakota DENR's State Implementation Plan (SIP) was approved by the EPA in May 2012. Under the SIP, the Big Stone plant must install and operate a new BART compliant air quality control system (AQCS) to reduce SO_2, NOx and particulate emissions as expeditiously as practicable, but no later than five years after the EPA's approval of the SIP. The estimated total project cost for the AQCS at the Big Stone plant is approximately $384 million (our share is 23.4%). As of December 31, 2014, we have capitalized costs of approximately $71.8 million related to this project, which is expected to be operational by the end of 2015.

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

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

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

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

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

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

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

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

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

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

LEGAL PROCEEDINGS

Colstrip Litigation

On March 6, 2013, the Sierra Club and the MEIC (Plaintiffs) filed suit in the United States District Court for the District of Montana (Court) against the six individual owners of Colstrip, including us, as well as the operator or managing agent of the station (Defendants). On September 27, 2013, Plaintiffs filed an Amended Complaint for Injunctive and Declaratory Relief. The original complaint included 39 claims for relief based upon alleged violations of the Clean Air Act and the Montana State Implementation Plan. The Amended Complaint dropped claims associated with projects completed before 2001, the Title V claims and the opacity claims. The Amended Complaint alleged a total of 23 claims covering 64 projects.

In the Amended Complaint, Plaintiffs identified physical changes made at Colstrip between 2001 and 2012, that Plaintiffs allege (a) have increased emissions of 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. At the joint request of the parties, the Court extended various deadlines set a bench trial date for the liability portion of the case for June 8, 2015.

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

On August 27, 2014, the Plaintiffs filed their Second Amended Complaint, which alleges a total of 13 claims covering eight projects and seeks injunctive and declaratory relief, civil penalties (including $100,000 of civil penalties to be used for beneficial environmental projects), and recovery of their attorney fees. Defendants filed their Answer to the Second Amended Complaint on September 26, 2014. Since filing the Second Amended Complaint, Plaintiffs have indicated that they are no longer pursuing a number of claims and projects thereby reducing their total claims to eight relating to four projects. A bench trial is scheduled for November 16, 2015.

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

Billings Refinery Outage Claim

In August 2014, we received a demand letter from a refinery in Billings claiming that it had sustained damages of approximately $48.5 million as a result of a January 2014 electrical outage. We dispute the claim and intend to vigorously defend against it. We reported the refinery's claim to our insurance carrier under our primary insurance policy, which has a $2.0 million retention. This matter is in the initial stages and we cannot predict an outcome or estimate the amount or range of loss, if any, that would be associated with an adverse result.

Other Legal Proceedings

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

Sch. 19	MONTANA PLANT IN SERVICE - PROPANE			
	Account Number & Title	This Year Utility	Last Year Utility	% Change
1	**Local Storage Plant**			
2	3360 Land and Land Rights	$ 64,954	$ 64,954	0.00%
3	3363 Other Equipment	385,262	385,262	0.00%
4	**Total Local Storage Plant**	450,216	450,216	0.00%
5				
6	**Distribution Plant**			
7	3376 Mains	490,965	490,965	0.00%
8	3380 Services	493,066	493,066	0.00%
9	3381 Customers Meters and Regulators	33,429	33,429	0.00%
10	3382 Meter Installations	-	-	-
11	3389 Other Equipment	51,888	51,888	0.00%
12	**Total Distribution Plant**	1,069,348	1,069,348	0.00%
13	**Total Propane Plant in Service**	1,519,564	1,519,564	0.00%
14				
15	3107 Construction Work in Progress	-	-	-
16	3117 Gas in Underground Storage	39,566	24,075	64.34%
17				
18				
19	**TOTAL PROPANE PLANT**	$ 1,559,130	$ 1,543,639	1.00%
20				
21				

22	**CONSOLIDATED**	December 31,	
23	**PLANT IN SERVICE**	2014	2013
24			
25	Montana Electric	$ 2,972,401,600	$ 2,390,960,783
26	Yellowstone National Park	16,629,416	13,618,264
27	Montana Natural Gas (Includes CMP)	699,769,408	677,024,230
28	Common	93,665,528	86,730,756
29	Townsend Propane	1,519,564	1,519,564
30	South Dakota Electric	597,960,821	580,354,887
31	South Dakota Natural Gas	163,980,215	161,401,195
32	South Dakota Common	49,516,491	47,886,249
33	Asset Retirement Obligation	16,678,342	15,205,199
34	**TOTAL PLANT**	$ 4,612,121,385	$ 3,974,701,127

Sch. 20	MONTANA DEPRECIATION SUMMARY - PROPANE				
	Functional Plant Class	Plant Cost	This Year	Last Year	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Local Storage Plant	$ 385,262	$ 235,349	$ 227,335	2.08%
4					
5	Distribution	1,069,348	534,634	501,748	3.07%
6					
7					
8	**Total Accumulated Depreciation**	$ 1,454,610	$ 769,983	$ 729,083	
9					
10					
11					
12					

		December 31,	
13	**Consolidated**		
14	**Accumulated Depreciation**	2014	2013
15			
16	Montana Electric	$ 1,000,073,389	$ 946,560,375
17	Yellowstone National Park	9,582,851	9,224,628
18	Montana Natural Gas (Includes CMP)	267,809,946	250,184,290
19	Common	34,643,025	33,281,451
20	Townsend Propane	769,983	729,083
21	South Dakota Electric	268,707,554	261,015,837
22	South Dakota Natural Gas	75,774,427	72,029,599
23	South Dakota Common	15,531,797	13,624,280
24	Acquisition Writedown	59,503,577	62,208,066
25	Basin Creek Capital Lease	17,089,022	15,078,542
26	FIN 47	2,092,675	1,503,510
27	CWIP-Capital Retirement Clearing	-6,556,494	-6,741,583
28	**Total Consolidated Accum Depreciation**	$ 1,745,021,750	$ 1,658,698,078

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

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 120,686,353	$ 93,982,666	28.41%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	112,991,164	109,962,010	2.75%
6	Amortization, Net	10,574,124	2,858,210	269.96%
7	Other Noncash Charges to Net Income, Net	12,431,796	9,033,466	37.62%
8	Deferred Income Taxes, Net	(7,411,618)	47,108,947	-115.73%
9	Investment Tax Credit Adjustments, Net	(273,079)	(334,950)	18.47%
10	Change in Operating Receivables, Net	5,776,323	(26,616,918)	121.70%
11	Change in Materials, Supplies & Inventories, Net	761,534	537,664	41.64%
12	Change in Operating Payables & Accrued Liabilities, Net	(1,627,921)	16,651,383	-109.78%
13	Allowance for Funds Used During Construction (AFUDC)	(6,551,852)	(5,049,543)	-29.75%
14	Change in Other Assets & Liabilities, Net	(6,542,680)	(15,444,979)	57.64%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(4,314,407)	(2,416,238)	-78.56%
17	Change in Regulatory Assets	7,306,869	(36,983,179)	119.76%
18	Change in Regulatory Liabilities	3,617,352	(4,719,283)	176.65%
19	**Net Cash Provided by Operating Activities**	247,423,958	188,569,255	31.21%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(1,172,692,087)	(300,103,374)	-290.76%
22	(Net of AFUDC)			
23	Proceeds from Sale of Assets	1,535,499	3,765,819	-59.23%
24	Other Investing activities	(34,527,780)	-	-
25	**Net Cash Used in Investing Activities**	(1,205,684,368)	(296,337,555)	>-300.00%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	505,789,025	100,000,000	>300.00%
29	Issuance of Short Term Borrowings, Net	126,890,525	18,015,652	>300.00%
30	Proceeds From Issuance of Common Stock, Net	399,207,125	56,825,170	>300.00%
31	Payments for Retirement of:			
32	Capital Lease Obligations, Net	(89,403)	(148,500)	39.80%
33	Repayments of Short Term Borrowings, Net	-	-	-
34	Dividends on Common Stock	(65,019,105)	(57,683,552)	-12.72%
35	Other Financing Activities:			
36	Debt Financing Costs	(5,247,637)	(7,593,330)	30.89%
37	Treasury Stock Activity	(814,026)	(1,041,694)	21.86%
38	**Net Cash (Used in)/Provided by Financing Activities**	960,716,504	108,373,746	>300.00%
39	**Net (Decrease)/Increase in Cash and Cash Equivalents**	2,456,094	605,446	>300.00%
40	**Cash and Cash Equivalents at Beginning of Year**	10,427,560	9,822,114	6.16%
41	**Cash and Cash Equivalents at End of Year**	$ 12,883,654	$ 10,427,560	23.55%
42				
43	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
44	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
45	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
46	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4 and the Hydro Transaction.			
47				

Sch. 24	MONTANA LONG TERM DEBT 1/								
	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
1									
2	**First Mortgage Bonds**								
3	6.34% Series, Due 2019	03/26/09	04/01/19	$ 250,000,000	$ 247,657,313	$ 249,928,812	6.34%	$ 16,514,170	6.61%
4	5.71% Series, Due 2039	10/15/09	10/15/39	55,000,000	54,450,000	55,000,000	5.71%	3,158,845	5.74%
5	6.04% Series, Due 2016	09/13/06	09/01/16	150,000,000	148,302,298	149,987,750	6.04%	9,308,114	6.21%
6	5.01% Sr Notes ($225M), Due 2025	05/27/10	05/01/25	161,000,000	160,075,635	161,000,000	5.01%	8,585,842	5.33%
5	4.15% Series($60M), Due 2042	08/10/12	08/10/42	60,000,000	59,623,329	60,000,000	4.15%	2,502,562	4.17%
6	4.30% Series($60M), Due 2052	08/10/12	08/10/52	40,000,000	39,748,886	40,000,000	4.30%	1,726,280	4.32%
6	4.85% Series($65M), Due 2043	12/19/13	12/19/43	15,000,000	14,929,953	15,000,000	4.85%	730,429	4.87%
7	3.99% Series($35M), Due 2028	12/19/13	12/19/43	35,000,000	34,836,556	35,000,000	3.99%	1,409,064	4.03%
8	4.176% Series($450M), Due 2044	11/14/14	11/14/44	450,000,000	445,743,514	450,000,000	4.176%	19,548,923	4.34%
9	**Total First Mortgage Bonds**			$ 1,216,000,000	$ 1,205,367,484	$ 1,215,916,562		$ 63,484,230	5.22%
10									
11	**Pollution Control Bonds**								
12	4.65% Series, Due 2023	04/27/06	08/01/23	$ 170,205,000	$ 164,451,956	$ 170,205,000	4.65%	$ 8,467,855	4.98%
13									
14	**Total Pollution Control Bonds**			$ 170,205,000	$ 164,451,956	$ 170,205,000		$ 8,467,855	4.98%
15									
16	**Other Long-Term Debt**								
17	New Market Tax Credit Financing - New G.O Bldg	07/01/14	07/01/44	$ 26,976,900	$ 26,292,348	$ 26,976,900	1.146%	$ 333,771	1.24%
18									
19	**Total Other Long Term Debt**			$ 26,976,900	$ 26,292,348	$ 26,976,900		$ 333,771	1.24%
20									
21	**TOTAL LONG TERM DEBT**			$ 1,413,181,900	$ 1,396,111,788	$ 1,413,098,462		$ 72,285,856	5.12%
22									
23									
24	This schedule does not reflect our capital lease, which is the Basin Creek contract lease. That amount is $28,162,445.								
25									
26									
27									
28									
29									
30									
31									
32									
33									
34									
35									
36									
37									
38									

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

Sch. 26

COMMON STOCK

	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	38,749,060	$27.05				$45.38	$42.64	
February	38,838,028	27.37				47.05	43.92	
March	39,135,645	27.45	$1.17	$0.40		47.86	44.77	
April	39,136,327	27.59				48.93	46.60	
May	39,138,075	27.65				48.49	45.49	
June	39,139,365	27.27	0.20	0.40		52.49	47.28	
July	39,140,079	27.32				52.70	46.21	
August	39,142,044	27.40				48.76	45.24	
September	39,143,568	27.63	0.77	0.40		49.55	45.12	
October	39,145,513	27.72				53.45	45.14	
November	46,913,400	31.26				54.42	51.40	
December	46,914,811	31.50	0.87	0.40		58.70	52.02	
TOTAL Year End	40,156,177	$31.50	$3.01	$1.60	46.84%	$56.58		18.8

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2014.

Sch. 27	MONTANA EARNED RATE OF RETURN - PROPANE			
	Description	This Year	Last Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$1,519,564	$1,515,593	0.26%
3	108 Accumulated Depreciation	(749,533)	(710,295)	-5.52%
5	**Net Plant in Service**	$770,031	$805,298	-4.38%
6	Additions:			
7	Propane on Hand	$29,699	$31,454	-5.58%
9	**Total Additions**	$29,699	$31,454	-5.58%
10	Deductions:			
11	190 Accumulated Deferred Income Taxes	$75,268	$75,108	0.21%
13	**Total Deductions**	$75,268	$75,108	0.21%
14	**Total Rate Base**	$724,462	$761,644	-4.88%
15	**Net Earnings**	(20,108)	(30,389)	33.83%
16	**Rate of Return on Average Rate Base**	-2.776%	-3.990%	30.43%
17	**Rate of Return on Average Equity**	Not applicable	Not applicable	
19	**Major Normalizing and**			
20	**Commission Ratemaking Adjustments**			
23		None		
29	**Total Adjustments**			
30	**Revised Net Earnings**			
31	**Adjusted Rate of Return on Average Rate Base**			
32	**Adjusted Rate of Return on Average Equity**			

Sch. 28 MONTANA COMPOSITE STATISTICS - PROPANE

	Description	Amount
	Plant	
101	Plant in Service	$ 1,519,564
107	Construction Work in Progress	
117	Gas in Underground Storage	39,566
108, 111	Depreciation & Amortization Reserves	769,983
NET BOOK COSTS		789,147
	Revenues & Expenses	
400	Operating Revenues	830,472
Total Operating Revenues		830,472
401-402	Operation & Maintenance Expenses	756,518
403-407	Depreciation Expense	40,899
408.1	Taxes Other than Income Taxes	59,048
409-411	Federal & State Income Taxes	(5,884)
Total Operating Expenses		850,581
Net Operating Income		(20,109)
415-421.1	Other Income	-
421.2-426.5	Other Deductions	-
NET INCOME BEFORE INTEREST EXPENSE		$ (20,109)
	Average Customers	
	Residential	506
	Commercial / Industrial	70
TOTAL AVERAGE NUMBER OF CUSTOMERS		576
	Other Statistics	
	Average Annual Residential Use (Dkt)	53.4
	Average Annual Residential Cost per (Dkt)	$18.85
	Average Residential Monthly Bill	$83.85
	Plant in Service (Gross) per Customer	$2,638

Sch. 29	Montana Customer Information- Propane, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Townsend	1,878	506	70	-	576
2						
3						
4						
5						
6						
7						
8						
9	**Total**	1,878	506	70	-	576
10						
11						
12	1/ Customer populations represent an average of the 12 month period from 01/01/14 through 12/31/14.					

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	108	155	132
5	Finance	128	138	133
6	Regulatory Affairs	29	28	29
7	Distribution	528	517	523
8	Transmission	279	273	276
9	Supply	40	121	81
10	Legal	19	20	20
11				
12				
13				
14				
15				
16				
17				
18	**TOTAL EMPLOYEES**	1,133	1,254	1,194

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

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

Sch. 33	MONTANA SOURCES OF PROPANE SUPPLY				
		Dekatherm Volumes		Avg. Commodity Cost	
		2014 Year	2013 Year	2014 Year	2013 Year
1	**Name of Supplier**				
2					
3	AmeriGas	22,918		$11.2202	
4	Gibson Energy, LLC	26,205	45,311	$12.0863	$12.6963
5					
6	**Total Propane Supply Volumes**	49,123	45,311	$11.6822	$12.6963

Sch. 35	MONTANA CONSUMPTION AND REVENUES - PROPANE						
		Operating Revenues		Dkt Sold		Average Customers	
		2014 Year	2013 Year	2014 Year	2013 Year	2014 Year	2013 Year
1	**Sales of Propane**						
2							
3	Residential	$509,153	$502,361	27,009	24,880	506	501
4	Commercial / Industrial	321,319	279,402	17,405	14,272	70	69
5							
6							
7	TOTAL SALES	$830,472	$781,763	44,414	39,152	576	570