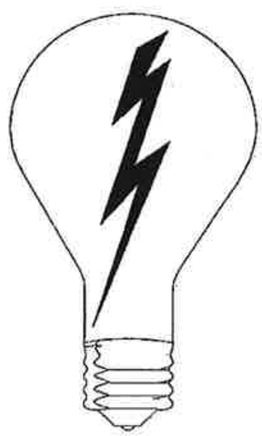
YEAR ENDING 2016

ANNUAL REPORT
OF

BLACK HILLS POWER, INC.

ELECTRIC UTILITY



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

Electric Annual Report

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IDENTIFICATION

Year: 2016

1.	Legal Name of Respondent:	Black Hills Power, Inc.
2.	Name Under Which Respondent Does Business:	Black Hills Energy
3.	Date Utility Service First Offered in Montana	2/23/1968
4.	Address to send Correspondence Concerning Report:	625 Ninth Street Rapid City, SD 57702
5.	Person Responsible for This Report:	Marne Jones Vice President - Regulatory
5a.	Telephone Number:	605-721-2348
Control Over Respondent		
1.	If direct control over the respondent was held by another entity at the end of year provide the following:	
	1a. Name and address of the controlling organization or person:	Black Hills Corporation 625 Ninth Street, Rapid City, SD 57701
	1b. Means by which control was held:	Common Stock
	1c. Percent Ownership:	100%

SCHEDULE 2

Board of Directors

Line No.	Name of Director and Address (City, State) (a)		Remuneration (b)
1	David R. Emery	Rapid City, SD	$ 0 (a)
2	Linden R. Evans	Rapid City, SD	$ 0 (a)
3	Richard W. Kinzley	Rapid City, SD	$ 0 (a)
4	Steven J. Helmers (b)	Rapid City, SD	$ 0 (a)
5	Brian G. Iverson (c)	Rapid City, SD	$ 0 (a)
6			
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9	(a) As officers of the company, they receive no compensation for their services as directors		
10	(b) Steven J. Helmers resigned effective April 25, 2016		
11	(c) Brian G. Iverson was elected on April 25, 2016		
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Officers

Year: 2016

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman and Chief Executive Officer		David R. Emery
2	President & Chief Operating Officer (a)		Linden R. Evans
3	Sr. Vice President & Chief Financial Officer		Richard W. Kinzley
4	Sr. Vice President and General Counsel		Brian G. Iverson
5	(also Chief Compliance Officer & Asst Sec) (b)		
6	Sr. Vice President (c)		Steven J. Helmers
7	Sr. Vice President-Chief Human Res Officer		Robert A. Myers
8	Sr. Vice President-Chief Information Officer		Scott A. Buchholz
9	Vice President-Governance & Corp Secretary		Roxann R. Basham
10	Vice President-Corporate Controller		Esther J. Newbrough
11	Vice President-Treasurer		Kimberly F. Nooney
12	Vice President-Strategic Planning & Dev		Jeffrey B. Berzina
13	Vice President-Human Resources (d)		Jennifer C. Landis
14	Vice President-Tax (e)		Melinda Lee Watkins
15	Assistant Corporate Secretary (f)		Amy K. Koenig
16	Group Vice President-Electric Utilities (g)		Stuart A. Wevik
17	Vice President-Operations Services (h)		Ivan Vancas
18	Vice President-Regulatory Strategy (i)		Kyle D. White
19	Vice President-Facilities (j)		Perry S. Krush
20	Vice President-Supply Chain (k)		Karen Beachy
21	Vice President-Power Gen, Safety & Environ (l)		Mark L. Lux
22	Vice President-Customer Service (m)		Mark E. Stege
23	Vice President-Operations (n)		Vance Crocker
24	Vice President-Gas Asset Optimization (o)		Jodi Culp
25	Vice President-Special Projects (p)		Richard C. Loomis
26			
27	(a) Linden R. Evans' title changed from President and Chief Operating Officer-Utilities to President and Chief		
28	Operating Officer effective January 1, 2016		
29	(b) Brian G. Iverson's title changed from Sr. Vice President-Regulatory & Government Affairs and Assistant		
30	General Counsel to Sr. Vice President & General Counsel effective April 25, 2016		
31	(c) Steven J. Helmers' title changed from Sr. Vice President, General Counsel and Chief Compliance Officer		
32	to Sr. Vice President effective April 25, 2016; he subsequently retired on July 1, 2016		
33	(d) Jennifer C. Landis was appointed Vice President-Human Resources on April 25, 2016		
34	(e) Melinda Lee Watkins was appointed Vice President-Tax on October 31, 2016		
35	(f) Amy K. Koenig was appointed Assistant Corporate Secretary on August 18, 2016		
36	(g) Stuart A. Wevik's title changed from Vice President-Utility Operations to Group Vice President-Electric		
37	Utilities effective January 1, 2016		
38	(h) Ivan Vancas' title changed from Vice President-Operations Services to Group Vice President-Natural Gas		
39	Utilities effective January 1, 2016; thereby removing him from an officer position for BHP		
40	(i) Kyle D. White's title changed from Vice President-Regulatory Affairs to Vice President-Regulatory		
41	Strategy effective August 18, 2016		
42	(j) Perry S. Krush's title changed from Vice President-Supply Chain to Vice President-Facilities effective		
43	September 12, 2016		
44	(k) Karen Beachy was appointed Vice President-Supply Chain on September 12, 2016		
45	(l) Mark L. Lux's title changed from Vice President and General Manager-Power Delivery to Vice President-		
46	Power Generation, Safety & Environmental effective January 1, 2016		
47	(m) Mark E. Stege was appointed Vice President-Customer Service on January 1, 2016		
48	(n) Vance Crocker's title changed from Vice President-BHP Operations to VP Operations on January 1, 2016		
49	(o) Jodi Culp was appointed Vice President-Gas Asset Optimization on February 12, 2016		
50	(p) Richard C. Loomis' title changed from Vice President-Energy Asset Optimization to Vice President-Special Projects on February 12, 2016; he subsequently was reassigned from that position on September 26, 2016		

CORPORATE STRUCTURE

Year: 2016

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	45,137,946	100.00%
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42				100.00%
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50	**TOTAL**		45,137,946	

Company Name: **Black Hills Power d/b/a Black Hills Energy** **SCHEDULE 5**

CORPORATE ALLOCATIONS

Year: 2016

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Not significant to Montana Operations					
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34	**TOTAL**					

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2016

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	Wyodak Resources Development Corp.	Coal Sales to Utility	Fair Market Value (based on similar arms-length transactions)	11,717,829	19.44%	687,837
2	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	5,485,123	3.45%	321,977
3	Black Hills Service Company	Information Technology, General Accounting, Insurance, Regulatory and Governmental Sevices, Facilities, Various Other Non-Power Goods and Services	Black Hills Service Company Cost Allocation Manual	22,665,977	44.65%	1,330,493
4	Black Hills Utility Holding Company	Various Non-power Goods and Services	Black Hills Utility Holdings Company Cost Allocation Manual	17,872,544	49.59%	1,049,118
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32	**TOTAL**			57,741,473		3,389,425

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2016

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	Wyodak Resources Development Corp.	Electricity	Wyoming Industrial Rate	1,023,370	100.00%	
2	Black Hills Wyoming	Transmission Service	Point to Point open Access Transmission Tariff	45,754	100.00%	
3	Cheyenne Light Fuel and Power	Transmission Service	Point to Point Open Access Transmission Tariff Fair Market Value	2,929,935	3.53%	171,987
4	Black Hills Colorado Electric	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	65	0.00%	4
5	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	3,067,747	3.69%	180,077
6	Black Hills Colorado Electric	Generation Dispatch	Fair Market Value (based on similar arms-length transactions	1,220,734	0.92%	71,657
7	Cheyenne Light Fuel and Power	Neil Simpson Complex	Fair Market Value (based on similar arms-length transactions	6,920,142	8.33%	406,212
8	Cheyenne Light Fuel and Power	Environmental Complex	Fair Market Value (based on similar arms-length transactions	137,042	0.16%	8,044
9	Cheyenne Light Fuel and Power	Generation Dispatch	Fair Market Value (based on similar arms-length transactions	957,337	1.15%	56,196
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32	TOTAL			16,302,126		894,177

MONTANA UTILITY INCOME STATEMENT

Year: 2016

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	277,396,391	266,884,357	-3.79%
2				
3	Operating Expenses			
4	401 Operation Expenses	136,129,741	125,032,548	-8.15%
5	402 Maintenance Expense	14,579,237	15,337,777	5.20%
6	403 Depreciation Expense	30,704,553	32,182,274	4.81%
7	404-405 Amortization of Electric Plant	1,749,909	1,749,909	
8	406 Amort. of Plant Acquisition Adjustments	97,406	97,406	
9	407 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Study Costs			
11	408.1 Taxes Other Than Income Taxes	6,210,180	6,740,112	8.53%
12	409.1 Income Taxes - Federal	14,079,653	3,057,557	-78.28%
13	- Other			
14	410.1 Provision for Deferred Income Taxes	33,053,195	30,699,722	-7.12%
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	(25,114,217)	(11,110,348)	55.76%
16	411.4 Investment Tax Credit Adjustments			
17	411.6 (Less) Gains from Disposition of Utility Plant			
18	411.7 Losses from Disposition of Utility Plant			
19				
20	**TOTAL Utility Operating Expenses**	211,489,657	203,786,957	-3.64%
21	**NET UTILITY OPERATING INCOME**	65,906,734	63,097,400	-4.26%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Electricity			
2	440 Residential	6,233	5,792	-7.08%
3	442 Commercial & Industrial - Small	22,650	19,791	-12.62%
4	Commercial & Industrial - Large	6,957,684	8,148,142	17.11%
5	444 Public Street & Highway Lighting			
6	445 Other Sales to Public Authorities			
7	446 Sales to Railroads & Railways			
8	448 Interdepartmental Sales			
9				
10	**TOTAL Sales to Ultimate Consumers**	6,986,567	8,173,725	16.99%
11	447 Sales for Resale			
12				
13	**TOTAL Sales of Electricity**	6,986,567	8,173,725	16.99%
14	449.1 (Less) Provision for Rate Refunds			
15				
16	**TOTAL Revenue Net of Provision for Refunds**	6,986,567	8,173,725	16.99%
17	Other Operating Revenues			
18	450 Forfeited Discounts & Late Payment Revenues	30	46	53.33%
19	451 Miscellaneous Service Revenues	15	15	
20	453 Sales of Water & Water Power			
21	454 Rent From Electric Property			
22	455 Interdepartmental Rents			
23	456 Other Electric Revenues			
24				
25	**TOTAL Other Operating Revenues**	45	61	35.56%
26	**Total Electric Operating Revenues**	6,986,612	8,173,786	16.99%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2016

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	734,402	664,914	-9.46%
6	501 Fuel	20,058,106	19,511,987	-2.72%
7	502 Steam Expenses	1,688,286	1,962,298	16.23%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	815,567	740,016	-9.26%
11	506 Miscellaneous Steam Power Expenses	1,411,625	1,439,562	1.98%
12	507 Rents	2,256,931	2,332,596	3.35%
13				
14	TOTAL Operation - Steam	26,964,917	26,651,373	-1.16%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	1,238,903	1,594,138	28.67%
18	511 Maintenance of Structures	474,943	613,388	29.15%
19	512 Maintenance of Boiler Plant	4,442,261	4,243,344	-4.48%
20	513 Maintenance of Electric Plant	850,038	760,992	-10.48%
21	514 Maintenance of Miscellaneous Steam Plant	78,563	(67,527)	-185.95%
22				
23	TOTAL Maintenance - Steam	7,084,708	7,144,335	0.84%
24				
25	**TOTAL Steam Power Production Expenses**	34,049,625	33,795,708	-0.75%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2016

	Account Number & Title		Last Year	This Year	% Change
1		Power Production Expenses -continued			
2	Hydraulic Power Generation				
3	Operation				
4	535	Operation Supervision & Engineering			
5	536	Water for Power			
6	537	Hydraulic Expenses			
7	538	Electric Expenses			
8	539	Miscellaneous Hydraulic Power Gen. Expenses			
9	540	Rents			
10					
11		TOTAL Operation - Hydraulic			
12					
13	Maintenance				
14	541	Maintenance Supervision & Engineering			
15	542	Maintenance of Structures			
16	543	Maint. of Reservoirs, Dams & Waterways			
17	544	Maintenance of Electric Plant			
18	545	Maintenance of Miscellaneous Hydro Plant			
19					
20		TOTAL Maintenance - Hydraulic			
21					
22		**TOTAL Hydraulic Power Production Expenses**			
23					
24	Other Power Generation				
25	Operation				
26	546	Operation Supervision & Engineering	1,167,396	1,288,491	10.37%
27	547	Fuel	3,835,791	2,195,963	-42.75%
28	548	Generation Expenses	605,667	152,583	-74.81%
29	549	Miscellaneous Other Power Gen. Expenses	478,561	351,176	-26.62%
30	550	Rents	272,737	176,250	-35.38%
31					
32		TOTAL Operation - Other	6,360,152	4,164,463	-34.52%
33					
34	Maintenance				
35	551	Maintenance Supervision & Engineering	83,635	87,857	5.05%
36	552	Maintenance of Structures	4,160	2,182	-47.55%
37	553	Maintenance of Generating & Electric Plant	1,224,317	1,676,098	36.90%
38	554	Maintenance of Misc. Other Power Gen. Plant	91,811	214,399	133.52%
39					
40		TOTAL Maintenance - Other	1,403,923	1,980,536	41.07%
41					
42		**TOTAL Other Power Production Expenses**	7,764,075	6,144,999	-20.85%
43					
44	Other Power Supply Expenses				
45	555	Purchased Power	43,019,391	35,393,766	-17.73%
46	556	System Control & Load Dispatching	1,660,770	1,602,386	-3.52%
47	557	Other Expenses	35,432		-100.00%
48					
49		TOTAL Other Power Supply Expenses	44,715,593	36,996,152	-17.26%
50					
51		**TOTAL Power Production Expenses**	86,529,293	76,936,859	-11.09%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2016

	Account Number & Title	Last Year	This Year	% Change
1	Transmission Expenses			
2	Operation			
3	560 Operation Supervision & Engineering	1,077,849	1,012,414	-6.07%
4	561 Load Dispatching	2,568,967	2,828,114	10.09%
5	562 Station Expenses	261,170	534,443	104.63%
6	563 Overhead Line Expenses	69,154	71,896	3.97%
7	564 Underground Line Expenses			
8	565 Transmission of Electricity by Others	19,065,613	20,118,179	5.52%
9	566 Miscellaneous Transmission Expenses	102,690	407,527	296.85%
10	567 Rents			
11				
12	TOTAL Operation - Transmission	23,145,443	24,972,573	7.89%
13	Maintenance			
14	568 Maintenance Supervision & Engineering	1,918	(143)	-107.46%
15	569 Maintenance of Structures			
16	570 Maintenance of Station Equipment	190,231	109,001	-42.70%
17	571 Maintenance of Overhead Lines	123,359	217,218	76.09%
18	572 Maintenance of Underground Lines			
19	573 Maintenance of Misc. Transmission Plant	2,664	2,984	12.01%
20				
21	TOTAL Maintenance - Transmission	318,172	329,060	3.42%
22				
23	**TOTAL Transmission Expenses**	23,463,615	25,301,633	7.83%
24				
25	Distribution Expenses			
26	Operation			
27	580 Operation Supervision & Engineering	1,275,678	1,628,000	27.62%
28	581 Load Dispatching	479,227	311,018	-35.10%
29	582 Station Expenses	685,838	643,979	-6.10%
30	583 Overhead Line Expenses	381,647	350,237	-8.23%
31	584 Underground Line Expenses	276,511	266,302	-3.69%
32	585 Street Lighting & Signal System Expenses	536	604	12.69%
33	586 Meter Expenses	912,253	732,053	-19.75%
34	587 Customer Installations Expenses	8,612	416	-95.17%
35	588 Miscellaneous Distribution Expenses	1,096,523	1,716,896	56.58%
36	589 Rents	16,986	15,685	-7.66%
37				
38	TOTAL Operation - Distribution	5,133,811	5,665,190	10.35%
39	Maintenance			
40	590 Maintenance Supervision & Engineering	173	898	419.08%
41	591 Maintenance of Structures			
42	592 Maintenance of Station Equipment	182,882	108,229	-40.82%
43	593 Maintenance of Overhead Lines	3,453,411	3,894,456	12.77%
44	594 Maintenance of Underground Lines	360,400	353,604	-1.89%
45	595 Maintenance of Line Transformers	43,530	44,661	2.60%
46	596 Maintenance of Street Lighting, Signal Systems	225,105	207,548	-7.80%
47	597 Maintenance of Meters	119,870	116,046	-3.19%
48	598 Maintenance of Miscellaneous Dist. Plant	96,250	79,031	-17.89%
49				
50	TOTAL Maintenance - Distribution	4,481,621	4,804,473	7.20%
51				
52	**TOTAL Distribution Expenses**	9,615,432	10,469,663	8.88%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2016

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	49,314	39,089	-20.73%
4	902 Meter Reading Expenses	6,029	7,264	20.48%
5	903 Customer Records & Collection Expenses	2,125,488	1,678,152	-21.05%
6	904 Uncollectible Accounts Expenses	316,409	390,019	23.26%
7	905 Miscellaneous Customer Accounts Expenses	742,089	922,595	24.32%
8				
9	TOTAL Customer Accounts Expenses	3,239,329	3,037,119	-6.24%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	196,482	143,984	-26.72%
14	908 Customer Assistance Expenses	1,446,134	1,212,040	-16.19%
15	909 Informational & Instructional Adv. Expenses	18,065	13,699	-24.17%
16	910 Miscellaneous Customer Service & Info. Exp.	55,944	128,325	129.38%
17				
18	TOTAL Customer Service & Info Expenses	1,716,625	1,498,048	-12.73%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision			
23	912 Demonstrating & Selling Expenses	3,704	45	-98.79%
24	913 Advertising Expenses		1,465	#DIV/0!
25	916 Miscellaneous Sales Expenses			
26				
27	TOTAL Sales Expenses	3,704	1,510	-59.23%
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	14,217,986	12,895,829	-9.30%
32	921 Office Supplies & Expenses	3,162,635	3,485,016	10.19%
33	922 (Less) Administrative Expenses Transferred - Cr.	(786,276)	(2,342,790)	-197.96%
34	923 Outside Services Employed	2,364,140	2,682,127	13.45%
35	924 Property Insurance	823,556	612,740	-25.60%
36	925 Injuries & Damages	1,687,289	1,522,263	-9.78%
37	926 Employee Pensions & Benefits	968,632	413,359	-57.33%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	781,281	872,842	11.72%
40	929 (Less) Duplicate Charges - Cr.		(159,220)	#DIV/0!
41	930.1 General Advertising Expenses	299,028	370,775	23.99%
42	930.2 Miscellaneous General Expenses	717,010	1,204,367	67.97%
43	931 Rents	614,887	488,812	-20.50%
44				
45	TOTAL Operation - Admin. & General	24,850,168	22,046,120	-11.28%
46	Maintenance			
47	935 Maintenance of General Plant	1,290,812	1,079,373	-16.38%
48				
49	**TOTAL Administrative & General Expenses**	26,140,980	23,125,493	-11.54%
50				
51	**TOTAL Operation & Maintenance Expenses**	150,708,978	140,370,325	-6.86%

MONTANA TAXES OTHER THAN INCOME

Year: 2016

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	6,186	5,731	-7.36%
5	Montana PSC	14,574	22,110	51.71%
6	Franchise Taxes			
7	Property Taxes	214,429	285,792	33.28%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	16,653	17,620	5.81%
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51	**TOTAL MT Taxes Other Than Income**	251,842	331,253	31.53%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES Year: 2016

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Amounts to Montana are not significant				
2					
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49					
50	**TOTAL Payments for Services**				

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2016

	Description	Total Company	Montana	% Montana
1	None			
2				
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50	**TOTAL Contributions**			

Pension Costs

Year: 2016

1	Plan Name			
2	Defined Benefit Plan? _______YES_________________	Defined Contribution Plan? _____No____		
3	Actuarial Cost Method? _Poroject Unit Credit Method____	IRS Code: _401b_____________________		
4	Annual Contribution by Employer: _$820,000.00_________	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	65,959,129	71,177,890	7.91%
8	Service cost	606,260	796,738	31.42%
9	Interest Cost	2,499,488	2,955,602	18.25%
10	Plan participants' contributions	-		
11	Amendments	-		
12	Actuarial Gain	454,706	(5,649,118)	-1342.37%
13	~~Acquisition~~ Participant Transfers (ASC 715 Disclosure)	(1,331,496)	(37,920)	97.15%
14	Benefits paid	(3,214,632)	(3,284,063)	-2.16%
15	Benefit obligation at end of year	64,973,455	65,959,129	1.52%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	54,723,334	59,097,785	7.99%
18	Actual return on plan assets	2,484,807	(1,056,812)	-142.53%
19	~~Acquisition~~ Participant Transfers (ASC 715 Disclosure)	(925,253)	(33,576)	96.37%
20	Employer contribution	820,000	-	-100.00%
21	Plan participants' contributions	-	-	
22	Benefits paid	(3,214,632)	(3,284,063)	-2.16%
23	Fair value of plan assets at end of year	53,888,256	54,723,334	1.55%
24	**Funded Status**	(11,085,199)	(11,235,795)	-1.36%
25	Unrecognized net actuarial loss	18,878,752	19,678,169	4.23%
26	Unrecognized prior service cost	95,265	137,893	44.75%
27	Prepaid (accrued) benefit cost	7,888,818	8,580,267	8.76%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	4.27%	4.63%	8.43%
31	Expected return on plan assets	6.75%	6.75%	
32	Rate of compensation increase	3.47%	3.57%	2.84%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	606,260	796,738	31.42%
36	Interest cost	2,499,488	2,955,602	18.25%
37	Expected return on plan assets	(3,632,274)	(3,934,608)	-8.32%
38	Amortization of prior service cost	42,628	42,628	
39	Recognized net actuarial loss	1,995,347	2,196,221	10.07%
40	Net periodic benefit cost	1,511,449	2,056,581	36.07%
41				
42	**Montana Intrastate Costs:**			
43	Pension Costs			
44	Pension Costs Capitalized			
45	Accumulated Pension Asset (Liability) at Year End			
46	**Number of Company Employees:**			
47	Covered by the Plan	475	492	3.58%
48	Not Covered by the Plan			
49	Active	198	210	6.06%
50	Retired	216	215	-0.46%
51	Deferred Vested Terminated	61	67	9.84%

Line description changed for lines 13 and 19 to match ASC 175 Disclosure.

Company Name: **Black Hills Power d/b/a Black Hills Energy** **SCHEDULE 15**

Page 1of 2

Other Post Employment Benefits (OPEBS)

Year: 2016

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: ___________			
4	Order number: ___________			
5	Amount recovered through rates			
6	**Weighted-average Assumptions as of Year End**			
7	Discount rate	3.84%	4.03%	4.95%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	5.10%	5.78%	13.33%
10	Actuarial Cost Method			
11	Rate of compensation increase	3.57%	3.57%	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13				
14				
15	**Describe any Changes to the Benefit Plan:**			
16				
17	**TOTAL COMPANY**			
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year	6,208,306	6,037,834	-2.75%
20	Service cost	203,529	233,125	14.54%
21	Interest Cost	186,705	213,886	14.56%
22	Plan participants' contributions	140,867	119,624	-15.08%
23	Amendments			
24	Actuarial Gain	(445,374)	(2,799)	99.37%
25	~~Acquisition~~ Participant Transfers (ASC 715 Disclosure)	(31,253)	(6,699)	78.56%
26	Benefits paid	(419,936)	(386,665)	7.92%
27	Benefit obligation at end of year	5,842,844	6,208,306	6.25%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year			
30	Actual return on plan assets			
31	~~Acquisition~~ Participant Transfers (ASC 715 Disclosure)			
32	Employer contribution	279,069	267,041	-4.31%
33	Plan participants' contributions	140,867	119,624	-15.08%
34	Benefits paid	(419,936)	(386,665)	7.92%
35	Fair value of plan assets at end of year	-	-	
36	**Funded Status**	(5,842,844)	(6,208,306)	-6.25%
37	Unrecognized net actuarial loss	99,369	572,042	475.67%
38	Unrecognized prior service cost	(2,186,221)	(2,521,960)	-15.36%
39	Prepaid (accrued) benefit cost	(7,929,696)	(8,158,224)	-2.88%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	203,529	233,125	14.54%
42	Interest cost	186,705	213,886	14.56%
43	Expected return on plan assets	-	-	
44	Amortization of prior service cost	(335,739)	(335,739)	
45	Recognized net actuarial loss			
46	Net periodic benefit cost	54,495	111,272	104.19%
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA			
49	Amount Funded through 401(h)			
50	Amount Funded through Other ___________			
51	TOTAL			
52	Amount that was tax deductible - VEBA			
53	Amount that was tax deductible - 401(h)			
54	Amount that was tax deductible - Other ___________			
55	TOTAL			

Line description changed for lines 25 and 31 to match ASC 175 Disclosure.

Other Post Employment Benefits (OPEBS) Continued

Year: 2016

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	407	439	7.86%
3	Not Covered by the Plan			
4	Active	260	270	3.85%
5	Retired	75	88	17.33%
6	Spouses/Dependants covered by the Plan	72	81	12.50%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost			
11	Interest Cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost			
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ________________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	N/A						
2							
3							
4							
5							
6							
7							
8							
9							
10							

Company Name: Black Hills Power d/b/a Black Hills Energy

SCHEDULE 17

Year: 2016

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	David R. Emery Chairman and Chief Executive Officer						
2	Richard W. Kinzley Sr. Vice President and Chief Financial Officer						
3	Linden R. Evans President and Chief Operating Officer						
4	Brian G. Iverson Sr. Vice President and General Counsel						
5	Scott A. Buchholz Sr. Vice President and Chief Information Officer						

*PLEASE REFER TO ATTACHED SCHEDULE 17A - THE SUMMARY COMPENSATION TABLE FROM THE BHC ANNUAL MEETING OF SHAREHOLDERS AND PROXY STATEMENT.

SUMMARY COMPENSATION TABLE

The following table sets forth the total compensation paid or earned by each of our Named Executive Officers for the years ended December 31, 2016, 2015 and 2014. We have no employment agreements with our Named Executive Officers.

Name and Principal Position	Year	Salary	Stock Awards(2)	Non-Equity Incentive Plan Compensation(3)	Changes in Pension Value and Nonqualified Deferred Compensation Earnings (4)	All Other Compensation(5)	Total
David R. Emery	2016	$767,000	$1,926,358	$1,283,218	$1,061,157	$104,751	$5,142,484
Chairman and Chief Executive Officer	2015	$738,333	$1,425,200	$613,241	$1,283,749	$70,979	$4,131,502
	2014	$715,500	$1,347,931	$1,177,092	$2,782,449	$63,661	$6,086,633
Richard W. Kinzley	2016	$357,500	$514,297	$362,027	$23,493	$174,154	$1,431,471
Sr. Vice President and Chief Financial Officer	2015	$326,241	$254,490	$151,520	$—	$160,404	$892,655
Linden R. Evans(1)	2016	$485,833	$773,875	$529,411	$37,711	$299,611	$2,126,441
President and Chief Operating Officer	2015	$462,833	$458,081	$277,556	$—	$356,843	$1,555,313
	2014	$448,500	$419,911	$533,688	$113,452	$305,840	$1,821,391
Brian G. Iverson(1)	2016	$325,000	$422,433	$246,837	$11,890	$111,429	$1,117,589
Sr. Vice President and General Counsel							
Scott A. Buchholz	2016	$302,500	$370,033	$228,137	$366,662	$112,969	$1,380,301
Sr. Vice President and Chief Information Officer							

(1) Mr. Evans was named President and Chief Operating Office effective January 1, 2016. Previously he was Chief Operating Officer of the Utilities. Mr. Iverson was named Sr. Vice President and General Counsel effective April 25, 2016. Previously he was Sr. Vice President - Regulatory and Government Affairs and Assistant General Counsel.

(2) Stock Awards represent the grant date fair value related to restricted stock and performance shares that have been granted as a component of long-term incentive compensation and the 2016 special achievement awards. The grant date fair value is computed in accordance with the provisions of accounting standards for stock compensation. Assumptions used in the calculation of these amounts are included in Note 12 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2016.

(3) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2016 awards at its January 24, 2017 meeting, and the awards were paid on February 24, 2017.

(4) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective years. These benefits have been valued using the assumptions disclosed in Note 18 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2016. Because these assumptions sometimes change between measurement dates, the change in value reflects not only the change in value due to additional benefits earned during the period and the passage of time but also reflects the change in value caused by changes in the underlying actuarial assumptions.

BALANCE SHEET

Year: 2016

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	1,115,816,370	1,115,598,920	0%
4	101.1 Property Under Capital Leases			
5	102 Electric Plant Purchased or Sold			
6	104 Electric Plant Leased to Others			
7	105 Electric Plant Held for Future Use	1,066,689	1,012,197	5%
8	106 Completed Constr. Not Classified - Electric	16,737,023	49,047,794	-66%
9	107 Construction Work in Progress - Electric	32,186,367	54,867,957	-41%
10	108 (Less) Accumulated Depreciation	(365,331,725)	(365,857,754)	0%
11	111 (Less) Accumulated Amortization			
12	114 Electric Plant Acquisition Adjustments	4,870,308	4,870,308	
13	115 (Less) Accum. Amort. Elec. Acq. Adj.	(3,424,147)	(3,521,554)	3%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	801,920,885	856,017,868	-6%
16				
17	**Other Property & Investments**			
18	121 Nonutility Property			
19	122 (Less) Accum. Depr. & Amort. for Nonutil. Prop.			
20	123 Investments in Associated Companies			
21	123.1 Investments in Subsidiary Companies			
22	124 Other Investments	4,733,684	4,841,229	-2%
23	125 Sinking Funds			
24	**TOTAL Other Property & Investments**	4,733,684	4,841,229	-2%
25				
26	**Current & Accrued Assets**			
27	131 Cash	294,333	230,639	28%
28	132-134 Special Deposits			
29	135 Working Funds	3,075	3,075	
30	136 Temporary Cash Investments			
31	141 Notes Receivable	13,905	8,372	66%
32	142 Customer Accounts Receivable	13,963,871	12,995,396	7%
33	143 Other Accounts Receivable	40,397,559	4,066,596	893%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(206,608)	(156,513)	-32%
35	145 Notes Receivable - Associated Companies	76,829,006	28,365,495	171%
36	146 Accounts Receivable - Associated Companies	6,733,964	9,525,744	-29%
37	151 Fuel Stock	4,943,559	3,321,107	49%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	17,709,660	18,119,769	-2%
41	155 Merchandise			
42	156 Other Material & Supplies			
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed	1,612,613	799,433	102%
45	165 Prepayments	3,481,482	3,523,967	-1%
46	171 Interest & Dividends Receivable			
47	172 Rents Receivable			
48	173 Accrued Utility Revenues	12,795,081	13,798,989	-7%
49	174 Miscellaneous Current & Accrued Assets	16,163	149,007	-89%
50	**TOTAL Current & Accrued Assets**	178,587,663	94,751,076	88%

BALANCE SHEET

Year: 2016

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Assets and Other Debits (cont.)**			
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	3,139,878	3,004,655	5%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
8a	182.3	Other Regulatory Assets	83,504,808	90,084,542	
9	183	Prelim. Survey & Investigation Charges	144,063	597,072	-76%
10	184	Clearing Accounts	763,517	605,688	26%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	212,135	3,452,998	-94%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	2,095,690	1,814,803	15%
16	190	Accumulated Deferred Income Taxes	30,565,748	15,707,242	95%
17		**TOTAL Deferred Debits**	120,425,839	115,267,000	4%
18					
19		**TOTAL Assets & Other Debits**	1,105,668,071	1,070,877,173	3%
		Account Title	Last Year	This Year	% Change
20					
21		**Liabilities and Other Credits**			
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	23,416,396	23,416,396	
26	202	Common Stock Subscribed			
27	204	Preferred Stock Issued			
28	205	Preferred Stock Subscribed			
29	207	Premium on Capital Stock	42,076,811	42,076,811	
30	211	Miscellaneous Paid-In Capital			
31	213	(Less) Discount on Capital Stock			
32	214	(Less) Capital Stock Expense	(2,501,882)	(2,501,882)	
33	215	Appropriated Retained Earnings			
34	216	Unappropriated Retained Earnings	330,295,328	322,933,274	2%
35	219	(Less) Accum Other Comprehensive Income	(1,306,744)	(1,262,188)	-4%
36		**TOTAL Proprietary Capital**	391,979,909	384,662,411	2%
37					
38	**Long Term Debt**				
39					
40	221	Bonds	340,000,000	340,000,000	
41	222	(Less) Reacquired Bonds			
42	223	Advances from Associated Companies			
43	224	Other Long Term Debt	2,855,000	2,855,000	
44	225	Unamortized Premium on Long Term Debt			
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.	(98,670)	(94,530)	-4%
46		**TOTAL Long Term Debt**	342,756,330	342,760,470	0%

BALANCE SHEET

Year: 2016

	Account Number & Title		Last Year	This Year	% Change
1					
2	**Total Liabilities and Other Credits (cont.)**				
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	668,005	612,567	9%
9	228.3	Accumulated Provision for Pensions & Benefits		19,543,755	-100%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	94	83,627	-100%
12	**TOTAL Other Noncurrent Liabilities**		668,099	20,239,949	-97%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	13,680,363	13,277,637	3%
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies	30,581,809	31,799,332	-4%
20	235	Customer Deposits	1,199,082	1,189,487	1%
21	236	Taxes Accrued	18,508,667	22,887,270	-19%
22	237	Interest Accrued	4,615,398	4,613,629	0%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	994,424	1,114,057	-11%
27	242	Miscellaneous Current & Accrued Liabilities	44,169,053	6,193,800	613%
28	243	Obligations Under Capital Leases - Current			
29	**TOTAL Current & Accrued Liabilities**		113,748,796	81,075,212	40%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	1,175,968	1,154,145	2%
34	253	Other Deferred Credits	21,183,042	1,433,092	1378%
34a	254	Other Regulatory Liabilities	13,452,047	12,325,181	
35	255	Accumulated Deferred Investment Tax Credits			
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	220,703,880	227,226,713	-3%
39	**TOTAL Deferred Credits**		256,514,937	242,139,131	6%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		1,105,668,071	1,070,877,173	3%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2016

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Intangible Plant**			
3				
4	301 Organization			
5	302 Franchises & Consents			
6	303 Miscellaneous Intangible Plant			
7				
8	**TOTAL Intangible Plant**			
9				
10	**Production Plant**			
11				
12	Steam Production			
13				
14	310 Land & Land Rights			
15	311 Structures & Improvements			
16	312 Boiler Plant Equipment			
17	313 Engines & Engine Driven Generators			
18	314 Turbogenerator Units			
19	315 Accessory Electric Equipment			
20	316 Miscellaneous Power Plant Equipment			
21				
22	**TOTAL Steam Production Plant**			
23				
24	Nuclear Production			
25				
26	320 Land & Land Rights			
27	321 Structures & Improvements			
28	322 Reactor Plant Equipment			
29	323 Turbogenerator Units			
30	324 Accessory Electric Equipment			
31	325 Miscellaneous Power Plant Equipment			
32				
33	**TOTAL Nuclear Production Plant**			
34				
35	Hydraulic Production			
36				
37	330 Land & Land Rights			
38	331 Structures & Improvements			
39	332 Reservoirs, Dams & Waterways			
40	333 Water Wheels, Turbines & Generators			
41	334 Accessory Electric Equipment			
42	335 Miscellaneous Power Plant Equipment			
43	336 Roads, Railroads & Bridges			
44				
45	**TOTAL Hydraulic Production Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2016

	Account Number & Title		Last Year	This Year	% Change
1					
2	Production Plant (cont.)				
3					
4	Other Production				
5					
6	340	Land & Land Rights			
7	341	Structures & Improvements			
8	342	Fuel Holders, Producers & Accessories			
9	343	Prime Movers			
10	344	Generators			
11	345	Accessory Electric Equipment			
12	346	Miscellaneous Power Plant Equipment			
13					
14	**TOTAL Other Production Plant**				
15					
16	**TOTAL Production Plant**				
17					
18	**Transmission Plant**				
19					
20	350	Land & Land Rights			
21	352	Structures & Improvements			
22	353	Station Equipment			
23	354	Towers & Fixtures			
24	355	Poles & Fixtures			
25	356	Overhead Conductors & Devices			
26	357	Underground Conduit			
27	358	Underground Conductors & Devices			
28	359	Roads & Trails			
29					
30	**TOTAL Transmission Plant**				
31					
32	**Distribution Plant**				
33					
34	360	Land & Land Rights	26,304	26,304	
35	361	Structures & Improvements	(4,805)	(4,805)	
36	362	Station Equipment	(454,255)	(442,870)	-3%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	431,386	431,399	0%
39	365	Overhead Conductors & Devices	481,159	480,898	0%
40	366	Underground Conduit	226	226	
41	367	Underground Conductors & Devices	13,144	13,144	
42	368	Line Transformers	62,681	85,284	-27%
43	369	Services	8,109	8,109	
44	370	Meters	856	856	
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49	**TOTAL Distribution Plant**		564,805	598,545	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2016

	Account Number & Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment			
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment			
12	397 Communication Equipment	425	425	
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	425	425	
17				
18	**TOTAL Electric Plant in Service**	565,230	598,970	

MONTANA DEPRECIATION SUMMARY

Year: 2016

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production				
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production				
6	Transmission				
7	Distribution	598,545	945,957	959,655	
8	General	425	220	78	
9	**TOTAL**	598,970	946,177	959,733	

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	N/A	N/A	
3	152 Fuel Stock Expenses Undistributed			
4	153 Residuals			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)			
9	Transmission Plant (Estimated)			
10	Distribution Plant (Estimated)			
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed			
16				
17	**TOTAL Materials & Supplies**			

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent	% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number 83.4.25			
2	Order Number 4998			
3				
4	Common Equity	52.83%	15.00%	7.92%
5	Preferred Stock	11.96%	9.03%	1.08%
6	Long Term Debt	35.21%	7.75%	2.73%
7	Other			
8	**TOTAL**	100.00%		11.73%
9				
10	Actual at Year End			
11				
12	Common Equity	52.88%		
13	Preferred Stock			
14	Long Term Debt	47.12%		
15	Other			
16	**TOTAL**	100.00%		

STATEMENT OF CASH FLOWS

Year: 2016

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	45,173,711	45,137,946	0%
6	Depreciation	32,551,868	34,029,589	-4%
7	Amortization			
8	Deferred Income Taxes - Net	7,938,978	19,589,374	-59%
9	Investment Tax Credit Adjustments - Net			
10	Change in Operating Receivables - Net	(2,406,330)	(5,762,062)	58%
11	Change in Materials, Supplies & Inventories - Net	(541,498)	1,892,680	-129%
12	Change in Operating Payables & Accrued Liabilities - Net	20,205,670	7,275,823	178%
13	Allowance for Funds Used During Construction (AFUDC)	(918,580)	(2,165,346)	58%
14	Change in Other Assets & Liabilities - Net	(11,589,477)	(10,313,859)	-12%
15	Other Operating Activities (explained on attached page)	1,953,029	(800,594)	344%
16	**Net Cash Provided by/(Used in) Operating Activities**	92,367,371	88,883,551	4%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(56,795,507)	(84,749,991)	33%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets			
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates	(36,687,182)	(4,095,242)	-796%
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	(127,272)	(102,012)	-25%
27	**Net Cash Provided by/(Used in) Investing Activities**	(93,609,961)	(88,947,245)	-5%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt			
32	Preferred Stock			
33	Common Stock			
34	Other:			
35	Net Increase in Short-Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt			
39	Preferred Stock			
40	Common Stock			
41	Other:			
42	Net Decrease in Short-Term Debt			
43	Dividends on Preferred Stock			
44	Dividends on Common Stock			
45	Other Financing Activities (explained on attached page)	(2,019)		N/A
46	**Net Cash Provided by (Used in) Financing Activities**	(2,019)		N/A
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(1,244,609)	(63,694)	-1854%
49	**Cash and Cash Equivalents at Beginning of Year**	1,542,017	297,408	418%
50	**Cash and Cash Equivalents at End of Year**	297,408	233,714	27%

Attachment 23A

Footnotes for Statement of Cash Flow — Year: 2016

Line 15, current year- Other Operating Activities consists of:

$	(716,979)	Regulatory assets and liabilities
$	484,582	Amortization
$	497,967	Employee benefit programs
$	397,018	Accounts receivable debt expense
$	334,156	Other current assets
$	(1,797,338)	Other non-current liabilities
$	(800,594)	Total

Line 15, last year - Other Operating Activities consists of:

$	2,403,208	Employee benefit plans
$	486,601	Amortization
$	(518,812)	Regulatory assets and liabilities
$	(278,194)	Other current and non-current assets
$	(463,193)	Other deferred credits non-current
$	323,419	Bad debt expense
$	1,953,029	Total

Line 26, current year-Other Investing Activities consist of:

$	(102,012)	Primarily an increase in cash surrender value for PEP insurance

Line 26, last year-Other Investing Activities consist of:

$	(127,272)	Primarily an increase in cash surrender value for PEP insurance

Line 45, last year-Other Financing Activities consist of:

$	(2,019)	Deferred financing costs

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 24**

LONG TERM DEBT

Year: 2016

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	Series AG	10/14	10/44	85,000,000	85,000,000	85,000,000	4.43%	3,789,394	4.46%
2									
3	Series AE	08/02	08/32	75,000,000	75,000,000	75,000,000	7.23%	5,519,913	7.36%
4									
5	Series AF	10/09	11/39	180,000,000	179,875,800	180,000,000	6.13%	11,105,056	6.17%
6									
7	1994 A Environmental								
8	Improvement Bonds	06/94	06/24	2,855,000	2,855,000	2,855,000	0.79%	24,740	0.87%
9									
10	Series Y	06/88	06/18	6,000,000	6,000,000		n/a	11,109	
11	Series Z	05/91	05/21	35,000,000	35,000,000		n/a	84,828	0.02%
12	Series AB	09/99	09/24	45,000,000	45,000,000		n/a	116,828	0.03%
13	Series 2004 Campbell County	10/04	10/24	12,200,000	12,200,000		n/a	68,121	0.02%
14									
15									
16	Line 7								
17	The Series 1994A bonds have a variable component that resets weekly. The rate reflected is the average								
18	interest rate for the year ended December 31, 2016.								
19									
20	Lines 10 thru 13								
21	Identified bonds have been paid off. However, FERC allows for unamortized deferred finance costs or loss on								
22	reacquired debt costs to be amortized over the original life of the bond. Annual costs reflect actual								
23	costs incurred as a percent of total principal outstanding for Black Hills Power.								
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			441,055,000	440,930,800	342,855,000		20,719,989	6.04%

PREFERRED STOCK

Year: 2016

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	N/A									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
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20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2016

		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
1	100% of common stock privately held by								
2	the Parent Company - Black Hills Corp								
3									
4	January	23,416,396							
5									
6	February	23,416,396							
7									
8	March	23,416,396							
9									
10	April	23,416,396							
11									
12	May	23,416,396							
13									
14	June	23,416,396							
15									
16	July	23,416,396							
17									
18	August	23,416,396							
19									
20	September	23,416,396							
21									
22	October	23,416,396							
23									
24	November	23,416,396							
25									
26	December	23,416,396							
27									
28									
29									
30									
31									
32	TOTAL Year End								

MONTANA EARNED RATE OF RETURN

Year: 2016

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service			
3	108 (Less) Accumulated Depreciation			
4	**NET Plant in Service**			
5				
6	Additions			
7	154, 156 Materials & Supplies			
8	165 Prepayments			
9	Other Additions			
10	**TOTAL Additions**			
11				
12	Deductions			
13	190 Accumulated Deferred Income Taxes			
14	252 Customer Advances for Construction			
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions			
17	**TOTAL Deductions**			
18	**TOTAL Rate Base**			
19				
20	**Net Earnings**			
21				
22	**Rate of Return on Average Rate Base**			
23				
24	**Rate of Return on Average Equity**			
25				
26	Major Normalizing Adjustments & Commission			
27	Ratemaking adjustments to Utility Operations			
28				
29				
30				
31	Note: This schedule is not completed because			
32	Montana revenues represents less than			
33	3.1% of the Company's revenue.			
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	**Adjusted Rate of Return on Average Rate Base**			
48				
49	**Adjusted Rate of Return on Average Equity**			

MONTANA COMPOSITE STATISTICS

Year: 2016

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	599
5	107	Construction Work in Progress	
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(960)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	(361)
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	8,174
18			
19	403 - 407	Depreciation & Amortization Expenses	
20		Federal & State Income Taxes	
21		Other Taxes	
22		Other Operating Expenses	
23		TOTAL Operating Expenses	
24			
25		Net Operating Income	8,174
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	8,174
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	12
36		Commercial	24
37		Industrial	5
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	41
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	75,810
45		Average Annual Residential Cost per (Kwh) (Cents) *	6
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	483
48		Gross Plant per Customer	(8.80)

MONTANA CUSTOMER INFORMATION

Year: 2016

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Carter and Powder River Counties	2,953	12	24	5	41
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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19						
20						
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24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**	2,953	12	24	5	41

MONTANA EMPLOYEE COUNTS

Year: 2016

	Department	Year Beginning	Year End	Average
1	N/A			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
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41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**			

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2017

	Project Description	Total Company	Total Montana
1	N/A		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
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43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**		

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2016

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	8	1000	364	270,711	75,796
2	Feb.	2	1900	342	230,920	60,005
3	Mar.	23	1200	316	227,885	58,125
4	Apr.	26	1300	305	192,324	38,253
5	May	5	1700	294	189,940	32,215
6	Jun.	24	1600	413	227,437	47,271
7	Jul.	20	1600	438	223,884	37,634
8	Aug.	10	1600	423	268,922	46,557
9	Sep.	1	1600	360	173,941	44,267
10	Oct.	1	1800	300	201,905	41,455
11	Nov.	29	900	343	219,340	50,938
12	Dec.	8	1800	389	277,698	65,179
13	**TOTAL**				2,704,907	597,695

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.					
15	Feb.	*Peak information maintained on a total system basis only				
16	Mar.					
17	Apr.					
18	May					
19	Jun.					
20	Jul.					
21	Aug.					
22	Sep.					
23	Oct.					
24	Nov.					
25	Dec.					
26	**TOTAL**					

TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,467,403	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,767,621
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	118,467	for Resale	114,502
7	(Less) Energy for Pumping			
8	**NET Generation**	1,585,870	Non-Requirements Sales	
9	Purchases	1,181,453	for Resale	729,823
10	Power Exchanges			
11	Received	8,402	Energy Furnished	
12	Delivered	60,817	Without Charge	
13	**NET Exchanges**	(52,415)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	6,860,016	Electric Utility	155,377
16	Delivered	6,860,016		
17	**NET Transmission Wheeling**	-	Total Energy Losses	(52,415)
18	Transmission by Others Losses			
19	**TOTAL**	2,714,908	**TOTAL**	2,714,908

SOURCES OF ELECTRIC SUPPLY

Year: 2016

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	80	6,576
2					
3	Thermal	Ben French	Rapid City, SD	10	(262)
4					
5	Thermal	Wyodak	Gillette, WY	69	442,102
6					
7	Thermal	Neil Simpson II	Gillette, WY	84	599,868
8					
9	Thermal	Lange	Rapid City, SD	39	11,657
10					
11	Thermal	Neil Simpson CT	Gillette, WY	39	9,158
12					
13	Thermal	Wygen III	Gillette, WY	57	608,948
14					
15	Combined Cycle	Cheyenne Prairie	Cheyenne, WY	60	91,373
16					
17	Purchase	See Schedule 32			1,181,453
18					
19	Wheeling	See Schedule 32			
20					
21	Total Interchange	See Schedule 32			(52,415)
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	**Total**			438	2,898,458

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2016

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1	N/A						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
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20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**						

Company Name: Schedule 35a

Electric Universal System Benefits Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	N/A					
3						
4						
5						
6						
7						
8	Market Transformation					
9						
10						
11						
12						
13						
14						
15	Renewable Resources					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Large Customer Self Directed					
36						
37						
38						
39						
40						
41						
42	Total					
43	Number of customers that received low income rate discounts					
44	Average monthly bill discount amount ($/mo)					
45	Average LIEAP-eligible household income					
46	Number of customers that received weatherization assistance					
47	Expected average annual bill savings from weatherization					
48	Number of residential audits performed					

Company Name:

Montana Conservation & Demand Side Management Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	N/A					
3						
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Other					
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46	Total					

MONTANA CONSUMPTION AND REVENUES

Year: 2016

	Sales of Electricity	Operating Revenues		MegaWatt Hours Sold		Avg. No. of Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$5,792	$6,233	76	77	12	12
2	Commercial - Small	19,791	22,650	176	215	24	23
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	8,148,142	6,957,684	117,010	110,761	5	5
6	Interruptible Industrial						
7	Public Street & Highway Lighting						
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities						
11	Interdepartmental						
12							
13	**TOTAL**	$8,173,725	$6,986,567	117,262	111,053	41	40

The following pages are the notes to the financial statements as reported in FERC FORM 1 2016 for Black Hills Power, Inc.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS
December 31, 2016 and 2015

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc., doing business as Black Hills Energy - South Dakota (the Company, "we," "us" or "our") is a regulated electric utility serving customers in South Dakota, Wyoming and Montana. We are a wholly-owned subsidiary of BHC or the Parent, a public registrant listed on the New York Stock Exchange.

Basis of Presentation

The financial statements include the accounts of Black Hills Power, Inc. and also our ownership interests in the assets, liabilities and expenses of our jointly owned facilities (Note 3).

The financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (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). Additionally, these requirement differ from GAAP related to the presentation of certain items discussed below.

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and this report differs from GAAP. The significant differences consist of the following:

- Comparative statements of net income per share are not presented.
- The accumulated reserve for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Current and long-term debt is classified in the balance sheet as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt separately.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.
- Uncertain tax positions related to temporary differences are classified in the Balance Sheets within the deferred tax accounts in accordance with regulatory treatment, as compared to other noncurrent liabilities for GAAP purposes. In addition, interest related to uncertain tax positions is recognized in interest expense in accordance with regulatory treatment, as compared to income tax expense for GAAP purposes.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent deferred debits and credits, respectively.
- Certain commodity trading purchases and sales transactions are presented gross as expense and revenues for the FERC presentation; however, the net margin is reported as net sales for the GAAP presentation.
- Various revenues and expenses are presented as other income and income deductions for the FERC presentation and reported as operating income and expense for the GAAP presentation.

Revisions

Certain revisions have been made to prior years' financial information to conform to the current year presentation.

We revised our presentation of cash and book overdrafts and certain cash transactions processed on behalf of affiliates. For accounts with the same financial institution where there is a banking arrangement that clears payments with balances in other bank accounts, book overdrafts are presented on a combined basis by bank as cash and cash equivalents. Cash collected or disbursed on behalf of affiliates is presented as Accounts Receivable from Associated Companies or Accounts Payable to Associated Companies. Prior year amounts were corrected to conform to the current year presentation, which decreased cash and cash equivalents by $7.3 million and $5.1 million as of December 31, 2015 and December 31, 2014, respectively; increased Accounts Receivable from Associated Companies by $1.0 million, increased Accounts Payable to Associated Companies by $0.6 million and decreased Accounts payable by $6.9 million as of December 31, 2015. It also decreased net cash flows provided by operations by $2.2 million for the year ended December 31, 2015. We assessed the materiality of these changes, taking into account quantitative and qualitative factors, and determined them to be immaterial to the balance sheet as of December 31, 2015 and to the statements of cash flows for the years ended December 31, 2015 and 2014. There is no impact to the Statements of Income, Statements of Comprehensive Income (Loss) or Statements of Common Stockholder's Equity for any period reported.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with FERC requires management 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. Actual results could differ from those estimates.

Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Regulatory Accounting

Our regulated electric operations are subject to regulation by various state and federal agencies. The accounting policies followed are generally subject to the Uniform System of Accounts of FERC.

Our regulated utility operations follow accounting standards for regulated operations and our financial statements reflect the effects of the different rate making principles followed by the various jurisdictions regulating our electric operations. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply to our regulated operations. In the event we determine that we no longer meet the criteria for following accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations in an amount that could be material.

We had the following regulatory assets and liabilities as follows as of December 31 (in thousands):

	Maximum Recovery Period (in years)	2016	2015
Regulatory assets:			
Deferred taxes on AFUDC (b)	45	9,367	8,571
Employee benefit plans (c)	12	20,100	20,866
Deferred energy costs (a)	1	23,016	19,875
Deferred taxes on flow through accounting (a)	35	12,545	12,104
Decommissioning costs (b)	8	12,456	13,686
Other regulatory assets (a) (d)	2	12,601	8,403
Total regulatory assets		$ 90,085	$ 83,505
Regulatory liabilities:			
Employee benefit plans (c)	12	12,304	12,616
Other regulatory liabilities (c)	13	21	836
Total regulatory liabilities		$ 12,325	$ 13,452

(a) Recovery of costs but we are not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base, respectively.
(d) Includes vegetation management expense of approximately $12.0 million and $5.0 million in 2016 and 2015, respectively.

Regulatory assets represent items we expect to recover from customers through rates.

Deferred Taxes on AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset itself is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity, and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income. In addition, this regulatory asset includes the income tax effect of the adjustment required under accounting for compensation-defined benefit plans to record the full pension and post-retirement benefit obligations. Such amounts have been grossed-up to reflect the revenue requirement associated with a rate regulated environment.

Deferred Energy Costs - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our utility customers that are either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission.

Deferred Taxes on Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. This regulatory treatment was applied to the tax benefit generated by repair costs that were previously capitalized for tax purposes in a rate case settlement that was reached in 2010. In this instance, the agreed upon rate increase was less than it would have been absent the flow-through treatment. A regulatory asset established to reflect the future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit consistent with the flow-through method with respect to costs considered repairs for tax purposes and are capitalized for book purposes.

Decommissioning Costs - We received approval in 2014 for regulatory treatment on the remaining net book values and decommissioning costs of our decommissioned coal plants.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Employee Benefit Plans - Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement aspect of a rate regulated environment.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable consists of sales to residential, commercial, industrial, municipal and other customers all of which do not bear interest. These accounts receivable are stated at billed and unbilled amounts net of write-offs or payment received.

We maintain an allowance for doubtful accounts which reflects our best estimate of uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectibility. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including unbilled revenue. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collection success given the existing collections environment.

Following is a summary of accounts receivable at December 31 (in thousands):

	2016	2015
Accounts receivable trade	$ 16,972	$ 15,268
Unbilled revenues	13,799	12,795
Allowance for doubtful accounts	(157)	(207)
Net accounts receivable trade	$ 30,614	$ 27,856

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price, delivery has occurred or services have been rendered, and collectibility is reasonably assured. Sales and franchise taxes collected from our customers is recorded on a net basis (excluded from Revenue).

Utility revenues are based on authorized rates approved by the state regulatory agencies and the FERC. Revenues related to the sale, transmission and distribution of energy, and delivery of service are generally recorded when service is rendered or energy is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month, and prices in effect in our jurisdictions. Each month a true-up of the estimated unbilled revenue amounts are recorded in Receivables-customers, net on the accompanying Balance Sheets.

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are generally stated on a weighted-average cost basis.

Deferred Financing Costs

Deferred financing costs are amortized using the effective interest method over the term of the related debt.

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost when placed in service. Included in the cost of regulated construction projects is AFUDC, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage, is charged to accumulated depreciation. At the time of such retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Depreciation provisions for regulated electric property, plant and equipment are computed on a straight-line basis using an annual composite rate of 2.2% in 2016, 2.3% in 2015 and 2.3% in 2014.

Derivatives and Hedging Activities

From time to time we utilize risk management contracts including forward purchases and sales to hedge the price of fuel for our combustion turbines and fixed-for-float swaps to fix the interest on any variable rate debt. Contracts that qualify as derivatives under accounting standards for derivatives, and that are not exempted such as normal purchase/normal sale, are required to be recorded in the balance sheet as either an asset or liability, measured at its fair value. Accounting standards for derivatives require that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Accounting standards for derivatives allow hedge accounting for qualifying fair value and cash flow hedges. Gain or loss on a derivative instrument designated and qualifying as a fair value hedging instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk should be recognized currently in earnings in the same accounting period. Conversely, the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument should be reported as a component of other comprehensive income and be reclassified into earnings or as a regulatory asset or regulatory liability, net of tax, in the same period or periods during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

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 under the 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 amount of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric 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 was determined that a transaction designated as a normal purchase or normal sale no longer met the exceptions, the fair value of the related contract would be reflected as either an asset or liability, under the accounting standards for derivatives and hedging.

Fair Value Measurements

Accounting standards for fair value measurements provide a single definition of fair value 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 and also requires disclosures and establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values giving the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

Financial assets and liabilities carried at fair value are classified and disclosed in one of the following three categories:

Level 1 - Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities.

Level 2 - Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources.

Impairment of Long-Lived Assets

We periodically evaluate whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining balance of our long-lived assets. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, we would estimate the future cash flows expected to result from the use of the assets and their eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) was less than the carrying amount of the long-lived assets, we would recognize an impairment loss.

Income Taxes

We file a federal income tax return with other members of the Parent's consolidated group. For financial statement purposes, federal income taxes are allocated to the individual companies based on amounts calculated on a separate return basis.

We use the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

We recognize interest and penalties related to income tax matters in interest expense benefit on the Statements of Income.

We account for uncertainty in income taxes recognized in the financial statements in accordance with accounting standards for income taxes. The unrecognized tax benefit is classified within deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheets. See Note 6 for additional information.

(2) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in thousands):

	2016	2016 Weighted Average Useful Life (in years)	2015	2015 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Electric plant:						
Production	$ 581,384	46	$ 573,733	46	30	63
Transmission	147,398	48	117,708	48	40	70
Distribution	364,304	46	353,241	46	15	75
Plant acquisition adjustment (a)	4,870	32	4,870	32	32	32
General	88,114	23	88,939	22	3	65
Total plant-in-service	1,186,070		1,138,490			
Construction work in progress	54,868		32,186			
Total electric plant	1,240,938		1,170,676			
Less accumulated depreciation and amortization	(384,920)		(368,756)			
Electric plant net of accumulated depreciation and amortization	$ 856,018		$ 801,921			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 14 years remaining.

(3) JOINTLY OWNED FACILITIES

We use the proportionate consolidation method to account for our percentage interest in the assets, liabilities and expenses of the following facilities:

- We own a 20% interest in the Wyodak Plant (the "Plant"), a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and is the operator of the Plant. We receive our proportionate share of the Plant's capacity and are committed to pay our share of its additions, replacements and operating and maintenance expenses.

- We own a 35% interest in, and are the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the transmission tie is 400 MW, including 200 MW West to East and 200 MW from East to West. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

- We own a 52% interest in the Wygen III power plant. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and a proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations.

- We own 55 MW of Cheyenne Prairie, a 95 MW gas-fired power generation facility located in Cheyenne, Wyoming. Wyoming Electric owns the remaining 40 MW. This facility was placed into commercial operations on October 1, 2014. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

The investments in our jointly owned plants and accumulated depreciation are included in the corresponding captions in the accompanying Balance Sheets. Our share of direct expenses of the Plants is included in the corresponding categories of operating expenses in the accompanying Statements of Income. Each of the respective owners is responsible for providing its own financing.

As of December 31, 2016, our interests in jointly-owned generating facilities and transmission systems included on our Balance Sheets were as follows (in thousands):

Interest in jointly-owned facilities	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$ 113,611	$ 256	$ 55,878
Transmission Tie	$ 19,978	$ 13	$ 5,793
Wygen III	$ 138,261	$ 1,806	$ 17,635
Cheyenne Prairie	$ 91,365	$ 155	$ 6,015

(4) LONG-TERM DEBT

Long-term debt outstanding at December 31 was as follows (in thousands):

	Maturity Date	Interest Rate	2016	2015
First Mortgage Bonds due 2032	August 15, 2032	7.23%	$ 75,000	$ 75,000
First Mortgage Bonds due 2039	November 1, 2039	6.125%	180,000	180,000
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
Unamortized Discount, First Mortgage Bonds due 2039			(94)	(99)
Series 94A Debt [(a)]	June 1, 2024	0.88%	2,855	2,855
Long-term Debt			$ 342,761	$ 342,756

(a) Variable interest rate at December 31, 2016.

Net deferred financing costs of approximately $3.0 million and $3.1 million were recorded on the accompanying Balance Sheets in Deferred Debits at December 31, 2016 and 2015, respectively, and are being amortized over the term of the debt. Amortization of deferred financing costs of approximately $0.1 million, $0.1 million and $0.1 million for the years ended December 31, 2016, 2015 and 2014, respectively, are included in Interest expense on the accompanying Statements of Income.

Substantially all of our property is subject to the lien of the indenture securing our first mortgage bonds. First mortgage bonds may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. We were in compliance with our debt covenants at December 31, 2016.

Long-term Debt Maturities

Scheduled maturities of our outstanding long-term debt (excluding unamortized discounts) are as follows (in thousands):

2017	$	—
2018	$	—
2019	$	—
2020	$	—
2021	$	—
Thereafter	$	342,855

(5) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments at December 31 were as follows (in thousands):

	2016		2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents (a)	$ 234	$ 234	$ 297	$ 297
Long-term debt (b)	$ 339,756	$ 410,466	$ 339,616	$ 404,864

(a) Fair value approximates carrying value due to either short-term length of maturity or variable interest rates that approximate prevailing market rates and therefore is classified in Level 1 in the fair value hierarchy.

(b) Long-term debt is valued using the market approach based on observable inputs of quoted market prices and yields available for debt instruments either directly or indirectly for similar maturities and debt ratings in active markets and therefore is classified in Level 2 in the fair value hierarchy. The carrying amount of our variable rate debt approximates fair value due to the variable interest rates with short reset periods. For additional information on our long-term debt see Note 4.

The following methods and assumptions were used to estimate the fair value of each class of our financial instruments.

Cash and Cash Equivalents

Included in cash and cash equivalents is cash and overnight repurchase agreement accounts. As part of our cash management process, excess operating cash is invested in overnight repurchase agreements with our bank. Repurchase agreements are not deposits and are not insured by the U.S. Government, the FDIC or any other government agency and involve investment risk including possible loss of principal. We believe however, that the market risk arising from holding these financial instruments is minimal.

(6) INCOME TAXES

Income tax expense (benefit) from continuing operations for the years ended December 31 was as follows (in thousands):

	2016	2015
Current	$ 3,550	$ 14,438
Deferred	19,589	7,939
Total income tax expense	$ 23,139	$ 22,377

The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in thousands):

	2016	2015
Deferred tax assets:		
Employee benefits	$ 5,163	$ 4,683
Regulatory liabilities	9,099	9,908
Other	1,445	15,975
Total deferred tax assets	15,707	30,566
Deferred tax liabilities:		
Accelerated depreciation and other plant related differences (a)	(202,047)	(196,237)
Regulatory assets	(4,391)	(4,236)
Employee benefits	(3,075)	(3,003)
Deferred costs	(16,920)	(14,765)
Other	(794)	2,463
Total deferred tax liabilities	(227,227)	(220,704)
Net deferred tax assets (liabilities)	$ (211,520)	$ (190,138)

(a) To conform to the 2016 presentation of accelerated depreciation and other plant-related differences, 2015 is net of deferred tax liabilities of $8.6 million, previously presented as AFUDC Equity.

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2016	2015
Federal statutory rate	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.4)	(0.1)
AFUDC Equity	(0.9)	(0.6)
Flow through adjustments (a)	(0.9)	(0.9)
Tax credits	(0.1)	—
Other	0.6	—
	33.3%	33.4%

(a) The flow-through adjustments related primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to tax expense.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, included in Other deferred credits and other liabilities on the accompanying Balance Sheet (in thousands):

	2016	2015
Unrecognized tax benefits at January 1	$ 2,264	$ 1,623
Additions for prior year tax positions	1,194	888
Reductions for prior year tax positions	(682)	(247)
Settlements for prior year tax positions	(2,283)	—
Unrecognized tax benefits at December 31	$ 493	$ 2,264

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.2 million. The reductions for prior year tax positions relate primarily to the IRS settlement as discussed below.

We file income tax returns in the United States federal jurisdictions as a member of the BHC consolidated group.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in interest expense. During the years ended December 31, 2016 and 2015, the interest expense recognized was not material to our financial results.

In January 2016, we reached a settlement in principle with IRS Appeals with respect to research and development tax credits and deductions for tax years 2007 through 2009. The settlement resulted in a reduction of approximately $2.9 million excluding interest. Accumulated deferred income taxes were restored by approximately $0.6 million and approximately $2.3 million was reclassified to current taxes payable.

We do not anticipate total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statutes of limitations on or before December 31, 2017.

At December 31, 2016, we are no longer in a federal NOL carry forward position.

(7) COMPREHENSIVE INCOME

The components of the reclassification adjustments for the period, net of tax, included in Other Comprehensive Income were as follows (in thousands):

	Location on the Statements of Income	Amounts Reclassified from AOCI	
		2016	2015
Gains and Losses on cash flow hedges:			
Interest rate swaps gain (loss)	Interest expense	$ 64	$ 64
Income tax	Income tax benefit (expense)	(22)	319
Total reclassification adjustments related to cash flow hedges, net of tax		$ 42	$ 383
Amortization of defined benefit plans:			
Actuarial gain (loss)	Operations and maintenance	$ 82	$ 94
Income tax	Income tax benefit (expense)	(29)	(33)
Total reclassification adjustments related to defined benefit plans, net of tax		$ 53	$ 61

Derivatives designated as cash flow hedges relate to a treasury lock entered into in August 2002 to hedge $50 million of our First Mortgage Bonds due on August 15, 2032. The treasury lock cash settled on August 8, 2002, the bond pricing date, and resulted in a $1.8 million loss. The treasury lock is treated as a cash flow hedge and the resulting loss is carried in Accumulated other comprehensive loss and is being amortized over the life of the related bonds.

Balances by classification included within Accumulated other comprehensive loss on the accompanying Balance Sheets were as follows (in thousands):

	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2015	$ (635)	$ (672)	$ (1,307)
Other comprehensive income (loss)	42	3	45
As of December 31, 2016	$ (593)	$ (669)	$ (1,262)

	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2014	$ (1,018)	$ (801)	$ (1,819)
Other comprehensive income (loss)	383	129	512
As of December 31, 2015	$ (635)	$ (672)	$ (1,307)

(8) EMPLOYEE BENEFIT PLANS

Funded Status of Benefit Plans

We apply accounting standards for regulated operations, and accordingly, the unrecognized net periodic benefit cost that would have been reclassified to Accumulated other comprehensive income (loss) was alternatively recorded as a regulatory asset or regulatory liability, net of tax.

Defined Benefit Pension Plan

We have a defined benefit pension plan ("Pension Plan") covering certain eligible employees. The benefits for the Pension Plan are based on years of service and calculations of average earnings during a specific time period prior to retirement. The Pension Plan has been closed to new employees and certain employees who did not meet age and service based criteria.

Black Hills Retirement Plan assets are held in a Master Trust. Due to the plan merger on December 31, 2016, reporting beginning in 2017 will no longer represent an undivided interest in the Master Trust. Our Board of Directors has approved the Plans' investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plans' beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Plans' benefit payment obligations. The Pension Plans' assets consist primarily of equity, fixed income and hedged investments.

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2016, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 44% to 52% equity and other return-seeking assets, and 48% to 56% fixed-income liability-hedging assets, and the expected rate of return from the associated asset categories.

The expected long-term rate of return for investments was 6.75% for the 2016 and 2015 plan years. Our Pension Plan funding policy is in accordance with the federal government's funding requirements.

Pension Plan Assets

The percentages of total plan asset fair value by investment category of our Pension Plan assets at December 31 were as follows:

	2016	2015
Equity securities	28%	26%
Real estate	5	5
Fixed income funds	57	59
Cash and cash equivalents	2	1
Hedge funds	8	9
Total	100%	100%

Supplemental Non-qualified Defined Benefit Retirement Plans

We have various supplemental retirement plans ("Supplemental Plans") for key executives. The Supplemental Plans are non-qualified defined benefit plans. The Supplemental Plans are subject to various vesting schedules.

Supplemental Plan Assets

We fund our Supplemental Plans on a cash basis as benefits are paid.

Defined Benefit Postretirement Healthcare Plan

Employees who are participants in our Postretirement Healthcare Plan ("Healthcare Plan") and who retire on or after attaining minimum age and years of service requirements are entitled to postretirement healthcare benefits. These benefits are subject to premiums, deductibles, co-payment provisions and other limitations. We may amend or change the Healthcare Plan periodically. We are not pre-funding our retiree medical plan. We have determined that the Healthcare Plan's post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy.

Plan Assets

We fund our Healthcare Plans on a cash basis as benefits are paid.

Plan Contributions and Estimated Cash Flows

Cash contributions for pension plans are made directly to the Master Trust accounts. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Contributions for the years ended December 31 were as follows (in thousands):

	2016	2015
Defined Benefit Plans		
Defined Benefit Pension Plan	$ 820	$ —
Defined Benefit Postretirement Healthcare Plan	$ 279	$ 267
Supplemental Non-qualified Defined Benefit Plan	$ 221	$ 211
Defined Contribution Plans		
Company Retirement Contribution	$ 851	$ 811
Matching Contributions	$ 1,400	$ 1,423

While we do not have required contributions, we expect to make approximately $1.3 million in contributions to our Defined Benefit Pension Plan in 2017.

Fair Value Measurements

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect their placement within the fair value hierarchy levels. The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis as of December 31 (in thousands):

Defined Benefit Pension Plan — **2016**

	Level 1	Level 2	Level 3	NAV (a)	Total Fair Value
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 980	$ —	—	$ 980
Common Collective Trust - Equity	—	14,927	—	—	14,927
Common Collective Trust - Fixed Income	—	31,003	—	—	31,003
Common Collective Trust - Real Estate	—	347	—	2,300	2,647
Hedge Funds	—	—	—	4,331	4,331
Total investments measured at fair value	$ —	$ 47,257	$ —	6,631	$ 53,888

Defined Benefit Pension Plan — **2015**

	Level 1	Level 2	Level 3	NAV (a)	Total Fair Value
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 498	$ —	—	$ 498
Common Collective Trust - Equity	—	14,198	—	—	$ 14,198
Common Collective Trust - Fixed Income	—	32,615	—	—	$ 32,615
Common Collective Trust - Real Estate	—	418	—	2,113	$ 2,531
Hedge Funds	—	—	—	4,881	4,881
Total investments measured at fair value	$ —	$ 47,729	$ —	6,994	$ 54,723

(a) Certain investments that are measured at fair value using Net Asset Value "NAV" per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plans' benefit obligations and fair value of plan assets below.

Common Collective Trust - Cash and Cash Equivalents: This category is comprised of the AXA Equitable General Fixed Income Fund and Common Collective Trusts - cash and cash equivalents. The AXA Equitable General Fixed Income Fund is a fund of diversified portfolios, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately placed bonds and real estate as well as short-term bonds. Fair values of mortgage loans are measured by discounting future contractual cash flows to be received on the mortgage loans using interest rates which loans with similar characteristics have. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair values of public fixed maturity securities are generally based on prices obtained from independent valuation service providers with reasonableness prices compared with directly observable market trades. The fair values of privately placed securities are determined using a discounted cash flow model. These models use observable inputs with a discount rate based upon the average of spread surveys collected from private market intermediaries and industry sector of the issuer.

Common Collective Trust - Trust Funds: The Plan holds units of various Common Collective Trust Funds offered through a private placement. The units are valued daily using the NAV. The NAVs are based on the fair value of each fund's underlying investments. Level 1 assets are priced using quotes for trades occurring in active markets for the identical asset. Level 2 assets are priced using observable inputs for the asset (for example, interest rates and yield curves observable at commonly quoted intervals, volatilities, prepayment speeds, loss severities, credit risks, and default rates) or inputs that are derived principally from or corroborated by observable market data by correlation or other means (market-corroborated inputs). The Plan's investments in common collective trust funds, with the exception of shares of the common collective trust real estate are categorized as Level 2.

Common Collective Trust - Real Estate Fund: This fund is valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments, and rely on these reports for pricing the units of the fund.

Hedge Funds: Hedge funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. Generally, shares may be redeemed at the end of each quarter, with a 65 day notice and are limited to a percentage of total net asset value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

Plan Reconciliations

The following tables provide a reconciliation of the Employee Benefit Plan's obligations and fair value of assets, components of the net periodic expense and elements of regulatory assets and liabilities and AOCI (in thousands):

Benefit Obligations

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Defined Benefit Postretirement Healthcare Plan	
	2016	2015	2016	2015	2016	2015
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 65,959	$ 71,178	$ 3,426	$ 3,599	$ 6,208	$ 6,038
Service cost	606	797	—	—	204	233
Interest cost	2,499	2,956	122	142	187	214
Actuarial loss (gain)	455	(5,650)	78	(104)	(446)	27
Benefits paid	(3,215)	(3,284)	(222)	(211)	(420)	(387)
Plan participants transfer to affiliate (a)	(1,331)	(38)	—	—	(31)	(7)
Medicare Part D adjustment	—	—	—	—	—	(30)
Plan participants' contributions	—	—	—	—	141	120
Projected benefit obligation at end of year	$ 64,973	$ 65,959	$ 3,404	$ 3,426	$ 5,843	$ 6,208

A reconciliation of the fair value of Plan assets (as of the December 31 measurement date) is as follows (in thousands):

	Defined Benefit Pension Plan 2016	Defined Benefit Pension Plan 2015	Supplemental Non-qualified Defined Benefit Retirement Plans 2016	Supplemental Non-qualified Defined Benefit Retirement Plans 2015	Defined Benefit Postretirement Healthcare Plan 2016	Defined Benefit Postretirement Healthcare Plan 2015
Beginning fair value of plan assets	$ 54,723	$ 59,098	$ —	$ —	$ —	$ —
Investment income (loss)	2,485	(1,057)	—	—	—	—
Benefits paid	(3,215)	(3,284)	(221)	(211)	(420)	(387)
Participant contributions	—	—	—	—	279	120
Employer contributions	820	—	221	211	141	267
Plan participants transfer to affiliate[(a)]	(925)	(34)	—	—	—	—
Ending fair value of plan assets	$ 53,888	$ 54,723	$ —	$ —	$ —	$ —

(a) Change is related to the merger of the three defined benefit pension plans maintained by Black Hills Corporation into one plan as of December 31, 2016.

The funded status of the plans and amounts recognized in the Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plan 2016	Defined Benefit Pension Plan 2015	Supplemental Non-qualified Defined Benefit Retirement Plans 2016	Supplemental Non-qualified Defined Benefit Retirement Plans 2015	Non-pension Defined Benefit Postretirement Plan 2016	Non-pension Defined Benefit Postretirement Plan 2015
Regulatory asset (liability)	$ 18,974	$ 19,816	$ —	$ —	$ (2,087)	$ (1,946)
Current liability	$ —	$ —	$ (247)	$ (216)	$ (541)	$ (619)
Non-current liability	$ (11,085)	$ (11,236)	$ (3,157)	$ (3,210)	$ (5,302)	$ (5,587)

Accumulated Benefit Obligation (in thousands)

	Defined Benefit Pension Plan 2016	Defined Benefit Pension Plan 2015	Supplemental Non-qualified Defined Benefit Retirement Plans 2016	Supplemental Non-qualified Defined Benefit Retirement Plans 2015	Non-pension Defined Benefit Postretirement Healthcare Plan 2016	Non-pension Defined Benefit Postretirement Healthcare Plan 2015
Accumulated benefit obligation	$ 61,585	$ 62,240	$ 3,404	$ 3,426	$ 5,843	$ 6,208

Components of Net Periodic Expense (in thousands)

	Defined Benefit Pension Plan 2016	Defined Benefit Pension Plan 2015	Defined Benefit Pension Plan 2014	Supplemental Non-qualified Defined Benefit Retirement Plans 2016	Supplemental Non-qualified Defined Benefit Retirement Plans 2015	Supplemental Non-qualified Defined Benefit Retirement Plans 2014	Non-pension Defined Benefit Postretirement Healthcare Plan 2016	Non-pension Defined Benefit Postretirement Healthcare Plan 2015	Non-pension Defined Benefit Postretirement Healthcare Plan 2014
Service cost	$ 606	$ 797	$ 704	$ —	$ —	$ —	$ 204	$ 233	$ 222
Interest cost	2,499	2,956	2,991	122	142	146	187	214	241
Expected return on assets	(3,632)	(3,935)	(3,702)	—	—	—	—	—	—
Amortization of prior service cost (credits)	43	43	43	—	—	—	(337)	(336)	(335)
Recognized net actuarial loss (gain)	1,995	2,196	940	82	93	45	—	—	—
Net periodic expense	$ 1,511	$ 2,057	$ 976	$ 204	$ 235	$ 191	$ 54	$ 111	$ 128

Accumulated Other Comprehensive Income (Loss)

Amounts included in AOCI, after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 were as follows (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2016	2015	2016	2015	2016	2015
Net loss	$ —	$ —	$ 669	$ 672	$ —	$ —
Prior service cost	—	—	—	—	—	—
Total accumulated other comprehensive income (loss)	$ —	$ —	$ 669	$ 672	$ —	$ —

The amounts in AOCI, regulatory assets or regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2017 are as follows (in thousands):

	Defined Benefits Pension Plan	Supplemental Non-qualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
Net gain (loss)	$ 799	$ 51	$ —
Prior service cost	28	—	(218)
Total net periodic benefit cost expected to be recognized during calendar year 2017	$ 827	$ 51	$ (218)

Assumptions

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
	2016	2015	2014	2016	2015	2014	2016	2015	2014
Weighted-average assumptions used to determine benefit obligations:									
Discount rate	4.27%	4.63%	4.25%	4.12%	4.29%	3.98%	3.84%	4.03%	3.70%
Rate of increase in compensation levels	3.47%	3.57%	3.86%	N/A	N/A	N/A	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:									
Discount rate (a)	4.63%	4.25%	5.10%	4.29%	3.98%	4.68%	4.03%	3.70%	4.45%
Expected long-term rate of return on assets (b)	6.75%	6.75%	6.75%	N/A	N/A	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	3.57%	3.86%	3.86%	N/A	N/A	N/A	N/A	N/A	N/A

(a) The estimated discount rate for the merged Black Hills Corporation's Retirement Plan is 4.27% for the calculation of the 2017 net periodic pension costs.

(b) The expected rate of return on plan assets is 6.75% for the calculation of the 2017 net periodic pension cost.

The healthcare benefit obligation was determined at December 31 as follows:

	2016	2015
Healthcare trend rate pre-65		
Trend for next year	6.10%	6.35%
Ultimate trend rate	4.50%	4.50%
Year Ultimate Trend Reached	2024	2024
Healthcare trend rate post-65		
Trend for next year	5.10%	5.20%
Ultimate trend rate	4.50%	4.50%
Year Ultimate Trend Reached	2023	2023

We do not pre-fund our post-retirement benefit plan. The table below shows the estimated impacts of an increase or decrease to our healthcare trend rate for our Retiree Health Care Plan (in thousands):

Change in Assumed Trend Rate	Service and Interest Costs	Accumulated Periodic Postretirement Benefit Obligation
1% increase	$ 5	$ 125
1% decrease	$ (5)	$ (121)

Beginning in 2016, the Company changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. The new method uses the spot yield curve approach to estimate the service and interest costs by applying the specific spot rates along the yield curve used to determine the benefit obligations to relevant projected cash outflows. Previously, those costs were determined using a single weighted-average discount rate. The change does not affect the measurement of the total benefit obligations as the change in service and interest costs offset the actuarial gains and losses recorded in other comprehensive income. The new method provides a more precise measure of interest and service costs by improving the correlation between the projected benefit cash flows and the discrete spot yield curve rates. We accounted for this change as a change in estimate beginning in the first quarter of 2016. See "Pension and Postretirement Benefit Obligations" within our Critical Accounting Policies in Item 7 on this Form 10-K for additional details.

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Retirement Plans	Defined Benefit Postretirement Healthcare Plan
2017	$ 3,946	$ 247	$ 541
2018	$ 3,543	$ 243	$ 562
2019	$ 3,669	$ 241	$ 577
2020	$ 3,766	$ 237	$ 585
2021	$ 3,883	$ 330	$ 570
2022-2026	$ 20,663	$ 1,519	$ 2,456

Defined Contribution Plan

The Parent sponsors a 401(k) retirement savings plan in which our employees may participate. Participants may elect to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis, up to a maximum amount established by the Internal Revenue Service. The plan provides for company matching contributions and company retirement contributions. Employer contributions vest at 20% per year and are fully vested when the participant has 5 years of service.

(9) RELATED-PARTY TRANSACTIONS

Non-Cash Dividend to Parent

We recorded non-cash dividends to our Parent of approximately $53 million and $29 million in 2016 and 2015 respectively, and decreased the utility money pool note receivable, net for approximately $53 million and $29 million in 2016 and 2015, respectively.

Receivables and Payables

We have accounts receivable and accounts payable balances related to transactions with other BHC subsidiaries. These balances as of December 31 were as follows (in thousands):

	2016	2015
Receivable - affiliates	$ 9,526	$ 6,734
Accounts payable - affiliates	$ 31,799	$ 30,582

Money Pool Notes Receivable and Notes Payable

We have a Utility Money Pool Agreement (the Agreement) with BHC, Wyoming Electric and Black Hills Utility Holdings. Under the agreement, we may borrow from BHC however the Agreement restricts us from loaning funds to BHC or to any of BHCs' non-utility subsidiaries. The Agreement does not restrict us from making dividends to BHC. Borrowings under the agreement bear interest at the weighted average daily cost of our parent company's external borrowings as defined under the Agreement, or if there are no external funds outstanding on that date, then the rate will be the daily one month LIBOR rate plus 1.0%.

The cost of borrowing under the Utility Money Pool was 2.21% at December 31, 2016.

We had the following balances, including interest, with the Utility Money Pool as of December 31 (in thousands):

	2016	2015
Notes receivable (payable), net	$ 28,365	$ 76,829

Interest income relating to the Utility Money Pool for the years ended December 31, was as follows (in thousands):

	2016	2015
Interest income	$ 1,047	$ 1,153

Interest expense allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2016 and 2015, we were allocated $1.9 million and $2.1 million, respectively, of interest expense allocations from BHC.

Other Balances and Transactions

We have the following Power Purchase and Transmission Services Agreements with affiliated entities:

- An agreement, expiring September 3, 2028, with Wyoming Electric to acquire 15 MW of the facility output from Happy Jack. Under a separate inter-company agreement expiring on September 3, 2028, Wyoming Electric has agreed to sell up to 15 MW of the facility output from Happy Jack to us.

- An agreement, expiring September 30, 2029, with Wyoming Electric to acquire 20 MW of the facility output from Silver Sage. Under a separate inter-company agreement expiring on September 30, 2029, Wyoming Electric has agreed to sell 20 MW of energy from Silver Sage to us.

- A Generation Dispatch Agreement with Wyoming Electric that requires us to purchase all of Wyoming Electric's excess energy.

Related-party Gas Transportation Service Agreement

On October 1, 2014, we entered into a gas transportation service agreement with Wyoming Electric in connection with gas supply for Cheyenne Prairie. The agreement is for a term of 40 years, in which we pay a monthly service and facility fee for firm and interruptible gas transportation.

Related-party Revenue and Purchases

We had the following related-party transactions for the years ended December 31 included in the corresponding captions in the accompanying Statements of Income:

	2016	2015
	(in thousands)	
Revenues:		
Energy sold to Wyoming Electric	$ 2,440	$ 1,857
Rent from electric properties	$ 5,046	$ 4,772
Purchases:		
Purchase of coal from WRDC	$ 16,227	$ 16,401
Purchase of excess energy from Wyoming Electric	$ 252	$ 898
Purchase of renewable wind energy from Wyoming Electric - Happy Jack	$ 1,918	$ 1,578
Purchase of renewable wind energy from Wyoming Electric - Silver Sage	$ 3,300	$ 2,739
Corporate support services from Parent, Black Hills Service Company and Black Hills Utility Holdings	$ 25,748	$ 26,655

(10) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2016	2015
	(in thousands)	
Non-cash investing and financing activities -		
Property, plant and equipment acquired with accrued liabilities	$ 5,521	$ 3,870
Non-cash decrease to money pool note receivable, net	$ (52,500)	$ (28,501)
Non-cash dividend to Parent company	$ 52,500	$ 28,501
Supplemental disclosure of cash flow information:		
Cash (paid) refunded during the period for -		
Interest (net of amounts capitalized)	$ (21,320)	$ (21,913)
Income taxes	$ —	$ —

(11) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

We have the following power purchase and transmission services agreements, not including related party agreements, as of December 31, 2016 (see Note 9 for information on related party agreements):

- A PPA with PacifiCorp expiring on December 31, 2023, which provides for the purchase by us of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants;
- A firm point-to-point transmission access agreement to deliver up to 50 MW of power on PacifiCorp's transmission system to wholesale customers in the western region through December 31, 2023; and
- An agreement with Thunder Creek for gas transport capacity, expiring on October 31, 2019.

Costs incurred under these agreements were as follows for the years ended December 31 (in thousands):

Contract	Contract Type	2016	2015
PacifiCorp	Electric capacity and energy	$ 12,221	$ 13,990
PacifiCorp	Transmission access	$ 1,428	$ 1,213
Thunder Creek	Gas transport capacity	$ 633	$ 633

Future Contractual Obligations

The following is a schedule of future minimum payments required under power purchase, transmission services, facility and vehicle leases, and gas supply agreements (in thousands):

2017	$	13,091
2018	$	6,388
2019	$	6,388
2020	$	6,388
2021	$	5,755
Thereafter	$	11,510

Long-Term Power Sales Agreements

We have the following power sales agreements as of December 31, 2016:

- An agreement with MDU to supply up to a maximum of 25 MW on a cost reimbursement basis during periods of reduced production at Wygen III;
- A capacity and energy agreement with MDU through December 31, 2023 to supply up to a maximum of 50 MW;
- An agreement with the City of Gillette to supply its first 23 MW on a cost reimbursement basis during periods of reduced production at Wygen III. Under this agreement, we will also provide the City of Gillette their operating component of spinning reserves;
- A unit-contingent energy and capacity sales agreement with MEAN expiring on May 31, 2023. This contract is based on up to 10 MW from Neil Simpson II and up to 10 MW from Wygen III based on the availability of these plants. The energy and capacity purchase requirements decrease over the term of the agreement; and
- A PPA with MEAN, expiring May 31, 2023. This contract is unit-contingent on up to 10 MW from Neil Simpson II and up to 10 MW from Wygen III based on the availability of these plants. The capacity purchase requirements decrease over the term of the agreement.

Effective January 1, 2017, we have an energy sales agreement with Cargill through December 31, 2021 to supply 50 MW of energy during heavy and light load timing intervals.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the consolidated financial statements.

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. They can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. Due to the environmental issues discussed below, we may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

Air

Our generation facilities are subject to federal, state and local laws and regulations relating to the protection of air quality. These laws and regulations cover, among other pollutants, carbon monoxide, SO_2, NO_x, mercury, hazardous air pollutants, particulate matter and GHG. Power generating facilities burning fossil fuels emit each of the foregoing pollutants and, therefore, are subject to substantial regulation and enforcement oversight by various governmental agencies.

Title IV of the Clean Air Act applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT, Lange CT, Wygen III and Wyodak plants. Title IV of the Clean Air Act created an SO_2 allowance trading program as part of the federal acid rain program. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2046.

The EPA issued the Industrial and Commercial Boiler Regulations for Area Sources of Hazardous Air Pollutants, with updates which impose emission limits, fuel requirements and monitoring requirements. The rule had a compliance deadline of March 21, 2014. In anticipation of this rule, we suspended operations at the Osage plant on October 1, 2010 and as a result of this rule, we suspended operations at the Ben French facility on August 31, 2012. We permanently retired Ben French, Osage and Neil Simpson I on March 21, 2014. The net book value of these plants was allowed regulatory accounting treatment and is recorded as a Regulatory Asset on the accompanying Balance Sheets.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Our Osage plant, permanently retired on March 21, 2014, had an on-site ash impoundment that was near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed in 2013 with the state providing closure certification in 2014. Post closure monitoring activities will continue for 30 years.

In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work was completed with the state providing closure certification in 2014. Post closure monitoring will continue for 30 years following the closure certification date.

(12) SUBSEQUENT EVENT

Management has evaluated and concluded that there were no significant subsequent events occurring after December 31, 2016 to February 28, 2017, the date the Black Hills Power's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 18, 2017. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.