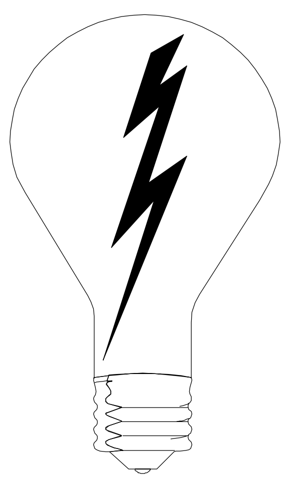
YEAR ENDING 2017

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

REVISED - 2005

Electric Annual Report

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IDENTIFICATION

Year: 2017

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:	PO Box 1400 Rapid City, SD 57709-1400
5.	Person Responsible for This Report:	Jason Keil Manager Regulatory
5a.	Telephone Number:	605-721-1500

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 7001 Mt. Rushmore Road Rapid City, SD 57702
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	Brian G. Iverson	Rapid City, SD	$ 0 (a)
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8	(a) As officers of the company, they receive no compensation for their services as directors		
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Officers

Year: 2017

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman and Chief Executive Officer		David R. Emery
2	President and Chief Operating Officer		Linden R. Evans
3	Senior Vice President and Chief Financial Officer		Richard W. Kinzley
4	Senior Vice President and General Counsel		Brian G. Iverson
5	(also Chief Compliance Officer and Assistant Secretary)		
6	Senior Vice President - (a)		Robert A. Myers
7	Senior Vice president - Chief Information Officer		Scott A. Buchholz
8	Senior Vice President - Chief Human Resources Officer - (b)		Jennifer C. Landis
9	Vice President - Governance and Corporate Secretary		Roxann R. Basham
10	Vice President - Corporate Controller		Esther J. Newbrough
11	Vice President - Treasurer		Kimberly F. Nooney
12	Vice President - Strategic Planning and Development		Jeffrey B. Berzina
13	Vice President - Tax		Melinda Lee Watkins
14	Assistant Corporate Secretary		Amy K. Koenig
15	Group Vice President - Electric Utilities		Stuart A. Wevik
16	Vice President - Regulatory Strategy		Kyle D. White
17	Vice President - Regulatory - (c)		Marne Jones
18	Vice president - Facilities		Perry S. Kush
19	Vice President - Supply Chain		Karen Beachy
20	Vice President - Power Generation, Safety and Environmental		Mark L. Lux
21	Vice President - Customer Service		Mark E. Stege
22	Vice President - Operations - (d)		Nick Gardner
23	Vice President - Operations - (e)		Vance Crocker
24	Vice President - Gas Asset Optimization		Jodi Culp
25			
26	(a) Robert A. Myers' title changed from Senior Vice President - Chief Human Resources Officer to Senior Vice President, effective February		
27	1, 2017; he subsequently retired on April 1, 2017		
28	(b) Jennifer C. Landis' title changed from Vice president - Human Resources to Senior Vice president - Chief Human Resources Officer,		
29	effective February 1, 2017		
30	(c) Marne Jones was appointed Vice President - Regulatory, effective February 1. 2017		
31	(d) Nick Gardner was appointed Vice President - Operations, effective September 5, 2017 replacing Vance Crocker		
32	(e) Vance Crocker was removed as Vice President - Operations, effective September 5, 2017		
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Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 4**

CORPORATE STRUCTURE

Year: 2017

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	51,298,462	100.00%
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42				100.00%
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50	**TOTAL**		51,298,462	

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

CORPORATE ALLOCATIONS

Year: 2017

	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: 2017

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)	11,757,220	17.65%	677,216
2	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	5,814,466	3.53%	334,913
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	24,953,684	43.87%	1,437,332
4	Black Hills Utility Holding Company	Various Non-power Goods and Services	Black Hills Utility Holdings Company Cost Allocation Manual	17,282,940	44.13%	995,497
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32	**TOTAL**			59,808,310		3,444,958

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2017

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	1,029,366	100.00%	
2	Black Hills Wyoming	Transmission Service	Point to Point open Access Transmission Tariff	14,138	100.00%	
3	Cheyenne Light Fuel and Power	Transmission Service	Point to Point Open Access Transmission Tariff Fair Market Value	3,643,841	4.20%	209,885
4	Black Hills Colorado Electric	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	35	0.00%	2
5	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	4,183,639	4.82%	240,978
6	Black Hills Colorado Electric	Generation Dispatch	Fair Market Value (based on similar arms-length transactions	1,539,153	1.23%	88,655
7	Cheyenne Light Fuel and Power	Neil Simpson Complex	Fair Market Value (based on similar arms-length transactions	7,733,161	8.91%	445,430
8	Cheyenne Light Fuel and Power	Environmental Complex	Fair Market Value (based on similar arms-length transactions	98,221	0.11%	5,658
9	Cheyenne Light Fuel and Power	Generation Dispatch	Fair Market Value (based on similar arms-length transactions	802,351	0.92%	46,215
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32	**TOTAL**			19,043,905		1,036,823

Company Name: Black Hills Power d/b/a Black Hills Energy SCHEDULE 8

MONTANA UTILITY INCOME STATEMENT

Year: 2017

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	266,884,357	287,647,578	7.78%
2					
3		Operating Expenses			
4	401	Operation Expenses	125,032,548	139,734,266	11.76%
5	402	Maintenance Expense	15,337,777	20,634,258	34.53%
6	403	Depreciation Expense	32,182,274	33,861,925	5.22%
7	404-405	Amortization of Electric Plant	1,749,909	1,902,824	8.74%
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	6,740,112	7,198,431	6.80%
12	409.1	Income Taxes - Federal	3,057,557	13,129,426	329.41%
13		- Other			
14	410.1	Provision for Deferred Income Taxes	30,699,722	26,116,270	-14.93%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(11,110,348)	(25,142,697)	-126.30%
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**	203,786,957	217,532,109	6.74%
21		**NET UTILITY OPERATING INCOME**	63,097,400	70,115,469	11.12%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	5,792	6,554	13.16%
3	442	Commercial & Industrial - Small	19,791	19,826	0.18%
4		Commercial & Industrial - Large	8,148,142	8,016,279	-1.62%
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**	8,173,725	8,042,659	-1.60%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	8,173,725	8,042,659	-1.60%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	8,173,725	8,042,659	-1.60%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	46	5,450	11747.83%
19	451	Miscellaneous Service Revenues	15	38	153.33%
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**	61	5,488	8896.72%
26		**Total Electric Operating Revenues**	8,173,786	8,048,147	-1.54%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2017

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	664,914	485,136	-27.04%
6	501 Fuel	19,511,987	18,959,100	-2.83%
7	502 Steam Expenses	1,962,298	1,739,019	-11.38%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	740,016	695,199	-6.06%
11	506 Miscellaneous Steam Power Expenses	1,439,562	1,618,628	12.44%
12	507 Rents	2,332,596	2,291,413	-1.77%
13				
14	TOTAL Operation - Steam	26,651,373	25,788,495	-3.24%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	1,594,138	1,829,833	14.79%
18	511 Maintenance of Structures	613,388	907,301	47.92%
19	512 Maintenance of Boiler Plant	4,243,344	5,595,150	31.86%
20	513 Maintenance of Electric Plant	760,992	1,703,066	123.80%
21	514 Maintenance of Miscellaneous Steam Plant	(67,527)	61,544	191.14%
22				
23	TOTAL Maintenance - Steam	7,144,335	10,096,894	41.33%
24				
25	**TOTAL Steam Power Production Expenses**	33,795,708	35,885,389	6.18%
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: 2017

	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	1,288,491	1,144,395	-11.18%
27	547 Fuel	2,195,963	3,742,585	70.43%
28	548 Generation Expenses	152,583	166,610	9.19%
29	549 Miscellaneous Other Power Gen. Expenses	351,176	367,047	4.52%
30	550 Rents	176,250	272,819	54.79%
31				
32	TOTAL Operation - Other	4,164,463	5,693,456	36.72%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	87,857	135,069	53.74%
36	552 Maintenance of Structures	2,182	52,405	2301.70%
37	553 Maintenance of Generating & Electric Plant	1,676,098	2,158,532	28.78%
38	554 Maintenance of Misc. Other Power Gen. Plant	214,399	143,762	-32.95%
39				
40	TOTAL Maintenance - Other	1,980,536	2,489,768	25.71%
41				
42	**TOTAL Other Power Production Expenses**	6,144,999	8,183,224	33.17%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	35,393,766	45,221,703	27.77%
46	556 System Control & Load Dispatching	1,602,386	1,871,993	16.83%
47	557 Other Expenses	-	(106)	
48				
49	TOTAL Other Power Supply Expenses	36,996,152	47,093,590	27.29%
50				
51	**TOTAL Power Production Expenses**	76,936,859	91,162,203	18.49%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2017

		Account Number & Title	Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	1,012,414	1,039,687	2.69%
4	561	Load Dispatching	2,828,114	3,092,752	9.36%
5	562	Station Expenses	534,443	431,397	-19.28%
6	563	Overhead Line Expenses	71,896	90,607	26.03%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	20,118,179	21,664,406	7.69%
9	566	Miscellaneous Transmission Expenses	407,527	526,340	29.15%
10	567	Rents			
11					
12		TOTAL Operation - Transmission	24,972,573	26,845,189	7.50%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	(143)	4,495	3243.36%
15	569	Maintenance of Structures			
16	570	Maintenance of Station Equipment	109,001	102,299	-6.15%
17	571	Maintenance of Overhead Lines	217,218	428,657	97.34%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant	2,984	36	-98.79%
20					
21		TOTAL Maintenance - Transmission	329,060	535,487	62.73%
22					
23		**TOTAL Transmission Expenses**	25,301,633	27,380,676	8.22%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	1,628,000	1,274,990	-21.68%
28	581	Load Dispatching	311,018	389,612	25.27%
29	582	Station Expenses	643,979	667,155	3.60%
30	583	Overhead Line Expenses	350,237	528,737	50.97%
31	584	Underground Line Expenses	266,302	378,209	42.02%
32	585	Street Lighting & Signal System Expenses	604		-100.00%
33	586	Meter Expenses	732,053	827,565	13.05%
34	587	Customer Installations Expenses	416	490	17.79%
35	588	Miscellaneous Distribution Expenses	1,716,896	2,346,236	36.66%
36	589	Rents	15,685	14,717	-6.17%
37					
38		TOTAL Operation - Distribution	5,665,190	6,427,711	13.46%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	898	7,837	772.72%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	108,229	131,515	21.52%
43	593	Maintenance of Overhead Lines	3,894,456	5,262,798	35.14%
44	594	Maintenance of Underground Lines	353,604	411,027	16.24%
45	595	Maintenance of Line Transformers	44,661	60,142	34.66%
46	596	Maintenance of Street Lighting, Signal Systems	207,548	154,126	-25.74%
47	597	Maintenance of Meters	116,046	66,019	-43.11%
48	598	Maintenance of Miscellaneous Dist. Plant	79,031	146,848	85.81%
49					
50		TOTAL Maintenance - Distribution	4,804,473	6,240,312	29.89%
51					
52		**TOTAL Distribution Expenses**	10,469,663	12,668,023	21.00%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2017

	Account Number & Title		Last Year	This Year	% Change
1		Customer Accounts Expenses			
2	Operation				
3	901	Supervision	39,089	88,969	127.61%
4	902	Meter Reading Expenses	7,264	21,128	190.86%
5	903	Customer Records & Collection Expenses	1,678,152	1,590,137	-5.24%
6	904	Uncollectible Accounts Expenses	390,019	577,515	48.07%
7	905	Miscellaneous Customer Accounts Expenses	922,595	726,878	-21.21%
8					
9		TOTAL Customer Accounts Expenses	3,037,119	3,004,627	-1.07%
10					
11		Customer Service & Information Expenses			
12	Operation				
13	907	Supervision	143,984	112,734	-21.70%
14	908	Customer Assistance Expenses	1,212,040	782,103	-35.47%
15	909	Informational & Instructional Adv. Expenses	13,699	39,859	190.96%
16	910	Miscellaneous Customer Service & Info. Exp.	128,325	75,520	-41.15%
17					
18		TOTAL Customer Service & Info Expenses	1,498,048	1,010,216	-32.56%
19					
20		Sales Expenses			
21	Operation				
22	911	Supervision	-		
23	912	Demonstrating & Selling Expenses	45	527	1071.11%
24	913	Advertising Expenses	1,465	2,097	43.14%
25	916	Miscellaneous Sales Expenses	-	766	
26					
27		TOTAL Sales Expenses	1,510	3,390	124.50%
28					
29		Administrative & General Expenses			
30	Operation				
31	920	Administrative & General Salaries	12,895,829	14,032,926	8.82%
32	921	Office Supplies & Expenses	3,485,016	3,742,167	7.38%
33	922	(Less) Administrative Expenses Transferred - Cr.	(2,342,790)	(2,606,516)	-11.26%
34	923	Outside Services Employed	2,682,127	3,201,947	19.38%
35	924	Property Insurance	612,740	509,871	-16.79%
36	925	Injuries & Damages	1,522,263	1,404,169	-7.76%
37	926	Employee Pensions & Benefits	413,359	449,543	8.75%
38	927	Franchise Requirements	-	-	
39	928	Regulatory Commission Expenses	872,842	1,029,565	17.96%
40	929	(Less) Duplicate Charges - Cr.	(159,220)	(184,613)	-15.95%
41	930.1	General Advertising Expenses	370,775	345,628	-6.78%
42	930.2	Miscellaneous General Expenses	1,204,367	1,110,703	-7.78%
43	931	Rents	488,812	832,199	70.25%
44					
45		TOTAL Operation - Admin. & General	22,046,120	23,867,589	8.26%
46	Maintenance				
47	935	Maintenance of General Plant	1,079,373	1,271,800	17.83%
48					
49		**TOTAL Administrative & General Expenses**	23,125,493	25,139,389	8.71%
50					
51		**TOTAL Operation & Maintenance Expenses**	140,370,325	160,368,524	14.25%

MONTANA TAXES OTHER THAN INCOME

Year: 2017

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	5,731	7,052	23.05%
5	Montana PSC	22,110	28,713	29.86%
6	Franchise Taxes			
7	Property Taxes	285,792	455,809	59.49%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	17,620	17,265	-2.01%
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51	**TOTAL MT Taxes Other Than Income**	331,253	508,839	53.61%

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 12**

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2017

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

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

SCHEDULE 13

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2017

	Description	Total Company	Montana	% Montana
1	None			
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49				
50	**TOTAL Contributions**			

Pension Costs

Year: 2017

1	Plan Name : Black Hills Retirement Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit Method	IRS Code: 401b		
4	Annual Contribution by Employer: $4,000,000	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	64,973,455	65,959,129	1.52%
8	Service cost	545,300	606,260	11.18%
9	Interest Cost	2,340,497	2,499,488	6.79%
10	Plan participants' contributions	-	-	
11	Amendments	-	-	
12	Actuarial Gain	4,007,686	454,706	-88.65%
13	Acquisition	(860,408)	(1,331,496)	-54.75%
14	Benefits paid	(3,444,748)	(3,214,632)	6.68%
15	Benefit obligation at end of year	67,561,782	64,973,455	-3.83%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	53,888,256	54,723,334	1.55%
18	Actual return on plan assets	6,150,214	2,484,807	-59.60%
19	Acquisition	(709,754)	(925,253)	-30.36%
20	Employer contribution	4,000,000	820,000	-79.50%
21	Plan participants' contributions	-	-	
22	Benefits paid	(3,444,748)	(3,214,632)	6.68%
23	Fair value of plan assets at end of year	59,883,968	53,888,256	-10.01%
24	**Funded Status**	(7,677,814)	(11,085,199)	-44.38%
25	Unrecognized net actuarial loss	18,945,377	18,878,752.00	-0.35%
26	Unrecognized prior service cost	52,637	95,265.00	80.98%
27	Prepaid (accrued) benefit cost	11,320,200	7,888,818	-30.31%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	3.71%	4.27%	15.09%
31	Expected return on plan assets	6.25%	6.75%	8.00%
32	Rate of compensation increase	3.43%	3.47%	1.20%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	545,300	606,260	11.18%
36	Interest cost	2,340,497	2,499,488	6.79%
37	Expected return on plan assets	(3,589,752.00)	(3,632,274.00)	-1.18%
38	Amortization of prior service cost	42,628.00	42,628.00	
39	Recognized net actuarial loss	1,229,945.00	1,995,347.00	62.23%
40	Net periodic benefit cost	568,618	1,511,449	165.81%
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	461	475	3.04%
48	Not Covered by the Plan			
49	Active	176	198	12.50%
50	Retired	220	216	-1.82%
51	Deferred Vested Terminated	65	61	-6.15%

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

Other Post Employment Benefits (OPEBS)

Year: 2017

	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	3.60%	3.84%	6.67%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	5.00%	5.10%	2.00%
10	Actuarial Cost Method			
11	Rate of compensation increase	N/A	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	5,842,844	6,208,306	6.25%
20	Service cost	206,063	203,529	-1.23%
21	Interest Cost	175,762	186,705	6.23%
22	Plan participants' contributions	99,801	140,867	41.15%
23	Amendments		-	
24	Actuarial Gain	129,633	(445,374)	-443.57%
25	Acquisition	(136,572)	(31,253)	77.12%
26	Benefits paid	(347,934)	(419,936)	-20.69%
27	Benefit obligation at end of year	5,969,597	5,842,844	-2.12%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	-	-	
30	Actual return on plan assets			
31	Acquisition			
32	Employer contribution	248,133.00	279,069.00	12.47%
33	Plan participants' contributions	99,801	140,867	41.15%
34	Benefits paid	(347,934)	(419,936)	-20.69%
35	Fair value of plan assets at end of year	-	-	
36	**Funded Status**	(5,969,597)	(5,842,844)	2.12%
37	Unrecognized net actuarial loss	92,430.00	99,369.00	7.51%
38	Unrecognized prior service cost	(1,850,482.00)	(2,186,221.00)	-18.14%
39	Prepaid (accrued) benefit cost	(7,727,649)	(7,929,696)	-2.61%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	206,063	203,529	-1.23%
42	Interest cost	175,762	186,705	6.23%
43	Expected return on plan assets	-	-	
44	Amortization of prior service cost	(335,739.00)	(335,739.00)	
45	Recognized net actuarial loss			
46	Net periodic benefit cost	46,086	54,495	18.25%
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	-	-	

Other Post Employment Benefits (OPEBS) Continued

Year: 2017

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	343	407	18.66%
3	Not Covered by the Plan			
4	Active	236	260	10.17%
5	Retired	76	75	-1.32%
6	Spouses/Dependants covered by the Plan	63	72	14.29%
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			

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

SCHEDULE 16

Year: 2017

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: 2017

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, 2017, 2016 and 2015. 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	2017	$812,000	$1,942,843	$560,232	$2,155,930	$92,930	$5,563,935
Chairman and Chief Executive Officer	2016	$767,000	$1,926,358	$1,283,218	$1,061,157	$104,751	$5,142,484
	2015	$738,333	$1,425,200	$613,241	$1,283,749	$70,979	$4,131,502
Richard W. Kinzley	2017	$378,000	$465,256	$141,983	$36,599	$250,572	$1,272,410
Sr. Vice President and Chief Financial Officer	2016	$357,500	$514,297	$362,027	$23,493	$174,154	$1,431,471
	2015	$326,241	$254,490	$151,520	$—	$160,404	$892,655
Linden R. Evans[(1)]	2017	$523,333	$818,045	$230,428	$59,631	$385,948	$2,017,385
President and Chief Operating Officer	2016	$485,833	$773,875	$529,411	$37,711	$299,611	$2,126,441
	2015	$462,833	$458,081	$277,556	$—	$356,843	$1,555,313
Brian G. Iverson[(1)]	2017	$346,667	$357,856	$97,823	$17,736	$145,405	$965,487
Sr. Vice President and General Counsel	2016	$325,000	$422,433	$246,837	$11,890	$111,429	$1,117,589
Scott A. Buchholz	2017	$317,500	$235,193	$99,376	$366,235	$133,407	$1,151,711
Sr. Vice President and Chief Information Officer	2016	$302,500	$370,033	$228,137	$366,662	$112,969	$1,380,301

(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 for 2016, include special achievement awards associated with the acquisition of SourceGas. 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, 2017.

(3) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2017 awards at its January 30, 2018 meeting, and the awards were paid on March 9, 2018.

(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, 2017. 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. This has created significant volatility in the past. The large change in pension value in 2017 was due to changes in the applicable mortality table and change in discount rates used to calculate the present value of these benefits. These changes accounted for 46 percent of the increase in Mr. Emery's pension value.

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

BALANCE SHEET

Year: 2017

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Electric Plant in Service	1,115,598,920	1,174,339,782	-5%
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	1,012,197	1,266,452	-20%
8	106	Completed Constr. Not Classified - Electric	49,047,794	131,061,091	-63%
9	107	Construction Work in Progress - Electric	54,867,957	4,832,298	1035%
10	108	(Less) Accumulated Depreciation	(365,857,754)	(403,933,945)	9%
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.	(3,521,554)	(3,618,960)	3%
14	120	Nuclear Fuel (Net)			
15		**TOTAL Utility Plant**	856,017,868	908,817,026	-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	4,841,229	4,926,313	-2%
23	125	Sinking Funds			
24		**TOTAL Other Property & Investments**	4,841,229	4,926,313	-2%
25					
26	**Current & Accrued Assets**				
27	131	Cash	230,639	13,245	1641%
28	132-134	Special Deposits			
29	135	Working Funds	3,075	2,575	19%
30	136	Temporary Cash Investments			
31	141	Notes Receivable	8,372		
32	142	Customer Accounts Receivable	12,995,396	15,812,276	-18%
33	143	Other Accounts Receivable	4,066,596	276,646	1370%
34	144	(Less) Accum. Provision for Uncollectible Accts.	(156,513)	(223,809)	30%
35	145	Notes Receivable - Associated Companies	28,365,495		
36	146	Accounts Receivable - Associated Companies	9,525,744	5,664,152	68%
37	151	Fuel Stock	3,321,107	2,660,435	25%
38	152	Fuel Stock Expenses Undistributed			
39	153	Residuals			
40	154	Plant Materials and Operating Supplies	18,119,769	19,102,008	-5%
41	155	Merchandise			
42	156	Other Material & Supplies			
43	157	Nuclear Materials Held for Sale			
44	163	Stores Expense Undistributed	799,433	1,598,604	-50%
45	165	Prepayments	3,523,967	3,496,664	1%
46	171	Interest & Dividends Receivable			
47	172	Rents Receivable			
48	173	Accrued Utility Revenues	13,798,989	13,280,661	4%
49	174	Miscellaneous Current & Accrued Assets	149,007	82,392	81%
50		**TOTAL Current & Accrued Assets**	94,751,076	61,765,849	53%

BALANCE SHEET

Year: 2017

	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	3,004,655	2,869,433	5%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
8a	182.3	Other Regullatory Assets	90,084,542	77,169,671	
9	183	Prelim. Survey & Investigation Charges	597,072	269,964	121%
10	184	Clearing Accounts	605,688	1,132,859	-47%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	3,452,998	3,476,576	-1%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	1,814,803	1,533,916	18%
16	190	Accumulated Deferred Income Taxes	15,707,242	29,587,154	-47%
17		**TOTAL Deferred Debits**	115,267,000	116,039,573	-1%
18					
19		**TOTAL Assets & Other Debits**	1,070,877,173	1,091,548,761	-2%
		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	322,933,274	332,498,719	-3%
35	217	(Less) Reacquired Capital Stock	(1,262,188)	(1,257,784)	0%
36		**TOTAL Proprietary Capital**	384,662,411	394,232,260	-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.	(94,530)	(90,390)	-5%
46		**TOTAL Long Term Debt**	342,760,470	342,764,610	0%

BALANCE SHEET

Year: 2017

	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	612,567	470,194	30%
9	228.3	Accumulated Provision for Pensions & Benefits	19,543,755	16,285,470	20%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	83,627	841,743	-90%
12		**TOTAL Other Noncurrent Liabilities**	20,239,949	17,597,407	15%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	13,277,637	13,962,360	-5%
18	233	Notes Payable to Associated Companies		13,486,723	-100%
19	234	Accounts Payable to Associated Companies	31,799,332	25,653,259	24%
20	235	Customer Deposits	1,189,487	1,393,629	-15%
21	236	Taxes Accrued	22,887,270	23,608,808	-3%
22	237	Interest Accrued	4,613,629	4,617,943	0%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	1,114,057	1,023,878	9%
27	242	Miscellaneous Current & Accrued Liabilities	6,193,800	5,112,681	21%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	81,075,212	88,859,281	-9%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	1,154,145	1,409,566	-18%
34	253	Other Deferred Credits	1,433,092	2,476,888	-42%
34a	254	Other Regulatory Liabilities	12,325,181	103,957,605	
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	227,226,713	140,251,144	62%
39		**TOTAL Deferred Credits**	242,139,131	248,095,203	-2%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		1,070,877,173	1,091,548,761	-2%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2017

	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**			

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 19**

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2017

	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	(442,870)	(442,870)	
37	363 Storage Battery Equipment			
38	364 Poles, Towers & Fixtures	431,399	439,151	-2%
39	365 Overhead Conductors & Devices	480,898	481,679	0%
40	366 Underground Conduit	226	226	
41	367 Underground Conductors & Devices	13,144	13,144	
42	368 Line Transformers	85,284	91,169	-6%
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**	598,545	612,963	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

	Account Number & Title		Last Year	This Year	% Change
1					Page 3 of 3
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**		598,970	613,388	

MONTANA DEPRECIATION SUMMARY

Year: 2017

	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	612,963	959,655	970,781	
8	General	425	78	102	
9	**TOTAL**	613,388	959,733	970,883	

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		53.49%		
13	Preferred Stock				
14	Long Term Debt		46.51%		
15	Other				
16	**TOTAL**		100.00%		

STATEMENT OF CASH FLOWS

Year: 2017

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	45,137,946	51,298,462	-12%
6	Depreciation	34,029,589	35,862,155	-5%
7	Amortization			
8	Deferred Income Taxes - Net	19,589,374	973,573	1912%
9	Investment Tax Credit Adjustments - Net			
10	Change in Operating Receivables - Net	(5,762,062)	4,342,206	-233%
11	Change in Materials, Supplies & Inventories - Net	1,892,680	(1,054,123)	280%
12	Change in Operating Payables & Accrued Liabilities - Net	7,275,823	(7,226,453)	201%
13	Allowance for Funds Used During Construction (AFUDC)	(2,165,346)	(2,165,232)	0%
14	Change in Other Assets & Liabilities - Net	(10,313,859)	978,617	-1154%
15	Other Operating Activities (explained on attached page)	(800,594)	(2,606,755)	69%
16	**Net Cash Provided by/(Used in) Operating Activities**	88,883,551	80,402,450	11%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(84,749,991)	(80,703,026)	-5%
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	(4,095,242)		
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	(102,012)	276,874	-137%
27	**Net Cash Provided by/(Used in) Investing Activities**	(88,947,245)	(80,426,152)	-11%
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:		(194,192)	100%
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)			
46	**Net Cash Provided by (Used in) Financing Activities**		(194,192)	100%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(63,694)	(217,894)	71%
49	**Cash and Cash Equivalents at Beginning of Year**	297,408	233,714	27%
50	**Cash and Cash Equivalents at End of Year**	233,714	15,820	1377%

Attachment 23A

Footnotes for Statement of Cash Flow **Year: 2017**

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

$	578,212	Bad debt expense
$	139,362	Deferred financing costs
$	817,285	Benefit plan expense
$	(4,000,000)	Benefit plan contribution
$	71,025	Change in regulatory assets and liabilities
$	(30,023)	Other changes in current and non-current assets
$	(246,947)	Other changes in current and non-current liabilities
$	64,332	Other comprehensive income
$	(2,606,754)	Total

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

$	397,018	Bad debt expense
$	484,582	Deferred financing costs
$	497,967	Benefit plan expense
$	(716,979)	Changes in regulatory assets and liabilities
$	334,156	Other changes in current and non-current assets
$	(1,797,338)	Bad debt expense
$	(800,594)	Total

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

$	190,271	Other investments
$	86,604	Proceeds from sale of assets
$	276,875	Total

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

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

Line 36, current year-Other Financing Activities consist of:

$	(194,192)	Borrowings from Money Pool

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

LONG TERM DEBT

Year: 2017

	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	1.01%	31,068	1.09%
9									
10	Series Y	6/15/88	6/15/18	6,000,000	6,000,000		n/a	11,109	
11	Series Z	5/29/91	5/29/21	35,000,000	35,000,000		n/a	84,828	
12	Series AB	9/1/99	9/1/24	45,000,000	45,000,000		n/a	116,828	
13	Series 2004 Campbell Co	10/1/04	10/1/24	12,200,000	12,200,000		n/a	68,121	
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, 2017.								
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 costs								
23	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		20,726,318	6.05%

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

SCHEDULE 25

PREFERRED STOCK

Year: 2017

	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										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

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

SCHEDULE 26

COMMON STOCK

Year: 2017

		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: 2017

	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: 2017

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	613
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	(971)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	(358)
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	8,043
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	8,043
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	8,043
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	12
36		Commercial	25
37		Industrial	6
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	43
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	95,590
45		Average Annual Residential Cost per (Kwh) (Cents) *	7
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	546
48		Gross Plant per Customer	(8.33)

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 29**

MONTANA CUSTOMER INFORMATION

Year: 2017

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Carter and Powder River Counties	2,903	12	25	6	43
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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23						
24						
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26						
27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**	2,903	12	25	6	43

Company Name: Black Hills Power d/b/a Black Hills Energy SCHEDULE 30

MONTANA EMPLOYEE COUNTS

Year: 2017

	Department	Year Beginning	Year End	Average
1	N/A			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
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37				
38				
39				
40				
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: 2018

	Project Description	Total Company	Total Montana
1	N/A		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
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41			
42			
43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**		

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2017

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	6	900	402	310,539	60,518
2	Feb.	3	800	385	250,681	39,696
3	Mar.	10	1100	354	269,209	54,282
4	Apr.	26	800	314	225,174	35,464
5	May	18	1200	295	235,165	35,496
6	Jun.	9	1700	389	244,896	32,006
7	Jul.	20	1500	447	296,115	45,463
8	Aug.	28	1700	392	252,618	52,487
9	Sep.	11	1700	381	265,663	32,875
10	Oct.	31	900	327	243,199	41,595
11	Nov.	6	1800	349	239,040	29,607
12	Dec.	30	1800	394	289,301	50,473
13	**TOTAL**				3,121,600	509,962

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	1,485,254	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,759,765
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	96,661	for Resale	136,354
7	(Less) Energy for Pumping			
8	**NET Generation**	1,581,915	Non-Requirements Sales	
9	Purchases	1,605,501	for Resale	1,096,267
10	Power Exchanges			
11	Received	11,819	Energy Furnished	
12	Delivered	77,635	Without Charge	
13	**NET Exchanges**	(65,816)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	6,844,378	Electric Utility	195,030
16	Delivered	6,844,378		
17	**NET Transmission Wheeling**	-	Total Energy Losses	(65,816)
18	Transmission by Others Losses			
19	**TOTAL**	3,121,600	**TOTAL**	3,121,600

SOURCES OF ELECTRIC SUPPLY

Year: 2017

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	3,502
2					
3	Thermal	Ben French	Rapid City, SD	10	(190)
4					
5	Thermal	Wyodak	Gillette, WY	69	540,930
6					
7	Thermal	Neil Simpson II	Gillette, WY	84	544,560
8					
9	Thermal	Lange	Rapid City, SD	39	8,889
10					
11	Thermal	Neil Simpson CT	Gillette, WY	39	12,854
12					
13	Thermal	Wygen III	Gillette, WY	57	400,705
14					
15	Combined Cycle	Cheyenne Prairie	Cheyenne, WY	60	71,603
16					
17	Purchase	See Schedule 32			1,605,501
18					
19	Wheeling	See Schedule 32			
20					
21	Total Interchange	See Schedule 32			(65,816)
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**			456	3,122,538.00

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

SCHEDULE 35

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2017

	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							
15							
16							
17							
18							
19							
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: Schedule 35b

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: 2017

	Sales of Electricity	Operating Revenues Current Year	Operating Revenues Previous Year	MegaWatt Hours Sold Current Year	MegaWatt Hours Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$6,554	$5,792	96	76	12	12
2	Commercial - Small	$19,826	$19,791	184	176	25	24
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	$8,016,279	$8,148,142	114,289	117,010	6	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**	$8,042,659	$8,173,725	114,568	117,262	43	41

The following pages are the notes to the financial statements as reported in FERC FORM 1 2017 for Black Hills Power, Inc.

NOTES TO FINANCIAL STATEMENTS
December 31, 2017 and 2016

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc., doing business as South Dakota Electric (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) and are prepared in accordance with GAAP.

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.
- 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.

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. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially 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. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply which could require these net regulatory assets to be charged to current income or OCI. Our regulatory assets represent amounts for which we will recover the cost, but generally are not allowed a return, except as described below. In the event we determine that our regulated net assets no longer meet the criteria for accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations, which could be material.

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

	Maximum Amortization (in years)	2017	2016
Regulatory assets			
Deferred taxes on AFUDC [(b)]	45	5,095	9,367
Employee benefit plans [(c)]	12	19,465	20,100
Deferred energy and fuel cost adjustments [(a)]	1	14,066	18,119
Deferred gas cost adjustments [(a)]	1	5,536	4,897
Deferred taxes on flow through accounting [(a)]	54	7,579	12,545
Decommissioning costs, net of amortization [(d)]	6	10,252	12,456
Vegetation management, net of amortization [(d)]	6	12,669	12,109
Other regulatory assets [(a) (d)]	6	2,508	492
		$ 77,170	$ 90,085
Regulatory liabilities			
Employee benefit plans and related deferred taxes [(c)]	12	6,808	12,304
Excess deferred income taxes [(c) (e)]	40	97,101	—
Other regulatory liabilities [(c)]	13	49	21
		$ 103,958	$ 12,325

(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.
(d) In accordance with a settlement agreement approved by the SDPUC on June 16, 2017, the amortization of South Dakota Electric's decommissioning costs of approximately $11 million, vegetation management costs of approximately $14 million, and Winter Storm Atlas costs of approximately $2.0 million are being amortized over 6 years, effective July 1, 2017. Decommissioning costs and Winter Storm Atlas costs were previously amortized over a 10 year period ending September 30, 2024. The vegetation management costs were previously unamortized. The change in amortization periods for these costs increased annual amortization expense by approximately $2.7 million.
(e) The increase in the regulatory tax liability is primarily related to the revaluation of deferred income tax balances at the lower income tax rate.

Regulatory assets represent items we expect to recover from customers through probable future increases in 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 plan 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 and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our customers that is 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. We file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by the applicable state utility commissions.

Deferred Gas Cost Adjustment - We have GCA provisions that allow us to pass the cost of gas on to our customers. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. We file periodic estimates of future gas costs based on market forecasts with state utility commissions

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. A regulatory asset was established to reflect that 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 for costs considered currently deductible for tax purposes, but 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.

Vegetation Management Costs - We received approval in 2013 for regulatory treatment on vegetation management maintenance costs for our distribution system rights-of-way.

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 associated with a rate regulated environment.

Excess Deferred Income Taxes - The revaluation of our deferred tax assets and liabilities due to the passage of the Tax Cuts and Jobs Act (TCJA) is recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA.

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 collectability.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.

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

	2017	2016
Accounts receivable, trade	$ 15,994	$ 16,972
Unbilled revenue	13,280	13,799
Less Allowance for doubtful accounts	(224)	(157)
Accounts receivable, net	$ 29,050	$ 30,614

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price and delivery has occurred or services have been rendered. Sales and franchise taxes collected from our customers are 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, our utilities 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 the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Balance Sheets.

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are recorded using the weighted-average cost method.

Deferred Financing Costs

Deferred financing costs are amortized over the estimated useful life 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.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Depreciation provisions for regulated electric property, plant and equipment are computed on a straight-line basis using an annual composite rate of 2.1% in 2017 and 2.2% in 2016.

Derivatives and Hedging Activities

The accounting standards for derivatives and hedging require that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value and changes in the derivative instruments be recognized in earnings unless specific hedge accounting criteria are met and designated accordingly, including the normal purchase and normal sales exception. Changes in the fair value for derivative instruments that do not meet this exception are recognized in the income statement as they occur.

From time to time we utilize risk management contracts including interest rate swaps to fix the interest on variable rate debt, or to lock in the Treasury yield component associated with anticipated issuance of senior notes. For swaps that settled in connection with the issuance of senior debt, the effective portion is deferred as a component in AOCI and recognized as interest expense over the life of the senior note. As of December 31, 2017, we have no outstanding interest rate swap agreements.

Revenues and expenses on contracts that qualify as derivatives may be elected to be accounted for under the normal purchases and normal sales exception 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 exception, 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

Assets and liabilities are classified and disclosed in one of the following fair value categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

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. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

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 the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Additional information is included in Note 5.

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.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA makes broad and complex changes to the U.S. tax code, including, but not limited to reducing the U.S. federal corporate tax rate from 35% to 21%. The Company uses the asset and liability method in accounting for income taxes. Under the asset and 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. As such, the Company has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017.

We use the deferral method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Such a method results in the investment tax credit being amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

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

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

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our financial statements.

(2) PROPERTY, PLANT AND EQUIPMENT

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

	2017	2017 Weighted Average Useful Life (in years)	2016	2016 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Electric plant:						
Production	$ 591,874	46	$ 581,584	46	40	54

Transmission	186,045	49	147,398	48	42	60
Distribution	375,214	46	364,304	46	21	62
Plant acquisition adjustment (a)	4,870	32	4,870	32	32	32
General	153,535	32	88,114	23	3	40
Total plant-in-service	1,311,538		1,186,070			
Construction work in progress	4,832		54,868			
Total electric plant	1,316,370		1,240,938			
Less accumulated depreciation and amortization	(407,553)		(384,920)			
Electric plant net of accumulated depreciation and amortization	$ 908,817		$ 856,018			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 13 years remaining.

(3) JOINTLY OWNED FACILITIES

Our financial statements include our share of several jointly-owned utility facilities as described below. Our share of the facilities' expenses are reflected in the appropriate categories of operating expenses in the Statements of Income (Loss). Each owner of the facility is responsible for financing its investment in the jointly-owned 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. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

As of December 31, 2017, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

Interest in jointly-owned facilities	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$ 114,405	$ 727	$ 58,955
Transmission Tie	$ 20,037	$ 242	$ 6,215
Wygen III	$ 138,688	$ 406	$ 19,239
Cheyenne Prairie	$ 91,631	$ 89	$ 8,746

(4) LONG-TERM DEBT

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

	Due Date	Interest Rate at December 31, 2017	Balance Outstanding December 31, 2017	Balance Outstanding December 31, 2016
First Mortgage Bonds due 2032	August 15, 2032	7.23%	$ 75,000	$ 75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
Less unamortized debt discount			(90)	(94)
Series 94A Debt [(a)]	June 1, 2024	1.83%	2,855	2,855
Long-term Debt			$ 342,765	$ 339,756

(a) Variable interest rate at December 31, 2017.

Net deferred financing costs of approximately $2.9 million and $3.0 million were recorded on the accompanying Balance Sheets in deferred debits at December 31, 2017 and 2016, respectively, and are being amortized over the term of the debt. Amortization of deferred financing costs of approximately $0.1 million for the years ended December 31, 2017 and 2016 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, 2017.

Long-term Debt Maturities

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

2018	$	—
2019	$	—
2020	$	—
2021	$	—
2022	$	—
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):

	2017 Carrying Value	2017 Fair Value	2016 Carrying Value	2016 Fair Value
Cash and cash equivalents [(a)]	$ 16	$ 16	$ 234	$ 234

Long-term debt (b)	$ 342,765	$ 446,978	$ 339,756	$ 410,466

(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 based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

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.

Long-Term Debt

For additional information on our long-term debt, see Note 4.

(6) INCOME TAXES

Income tax expense for the years ended December 31 was (in thousands):

	2017	2016
Current	$ 13,154	$ 3,550
Deferred	974	19,589
Total income tax expense	$ 14,128	$ 23,139

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

	2017	2016
Deferred tax assets:		
Employee benefits	$ 3,012	$ 5,163
Regulatory liabilities	24,984	9,099
Other	1,591	1,445
	29,587	15,707
Deferred tax liabilities:		
Accelerated depreciation and other plant related differences (a)	(122,002)	(202,047)
Regulatory assets	(7,008)	(4,391)
Employee benefits	(2,595)	(3,075)
Deferred costs	(8,447)	(16,920)
Other	(199)	(794)
	(140,251)	(227,227)
Net deferred tax asset (liability)	$ (110,664)	$ (211,520)

(a) The net deferred tax liabilities were revalued for the change in federal tax rate to 21% under the TCJA. The revaluation resulted in a reduction to net deferred tax liabilities of approximately $103 million. Due to the regulatory construct, approximately $97 million of the revaluation was reclassified to a regulatory liability.

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

	2017	2016
Federal statutory rate	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.1)	(0.4)
AFUDC Equity	(1.0)	(0.9)
Flow through adjustments (a)	(1.8)	(0.9)
Tax credits	—	(0.1)
Tax reform (b)	(9.2)	—
Other	(1.3)	0.6
	21.6%	33.3%

(a) 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. 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.
(b) On December 22, 2017, the TCJA was signed into law reducing the federal corporate rate from 35% to 21%, effective January 1, 2018. The 2017 effective tax rate reduction reflects the impact from reducing the regulatory liability related to the deferred tax rate change for the benefit of additional net operating loss carryforwards that exist for rate making purposes and will reduce the amount of future refunds.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, included within the deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheet (in thousands):

	2017	2016
Unrecognized tax benefits at January 1	$ 493	$ 2,264
Additions for current year tax positions	13	—
Additions for prior year tax positions	—	1,194
Reductions for prior year tax positions	(204)	(682)
Settlements for prior year tax positions	—	(2,283)
Unrecognized tax benefits at December 31	$ 302	$ 493

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is not material to the financial results of the Company.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in Other interest expense. During the years ended December 31, 2017 and 2016, the interest expense recognized was not material to the financial results of the Company.

We do not anticipate that 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, 2018.

At December 31, 2016, we were no longer in a federal NOL carryforward position.

(7) COMPREHENSIVE INCOME

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

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 (Loss)	Amounts Reclassified from AOCI	
		2017	2016
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$ 64	$ 64
Income tax	Income tax benefit (expense)	(22)	(22)
Total reclassification adjustments related to cash flow hedges, net of tax		$ 42	$ 42
Amortization of defined benefit plans:			
Actuarial gain (loss)	Operations and maintenance	$ 86	$ 82
Income tax	Income tax benefit (expense)	(30)	(29)
Total reclassification adjustments related to defined benefit plans, net of tax		$ 56	$ 53

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, 2016	$ (593)	$ (669)	$ (1,262)
Other comprehensive income (loss)	42	(38)	4
As of December 31, 2017	$ (551)	$ (707)	$ (1,258)

	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)

(8) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

BHC sponsors a 401(k) retirement savings plan (the 401(k) Plan). Participants in the 401(k) Plan may elect to invest a portion of their eligible compensation to the 401(k) Plan up to the maximum amounts established by the IRS. The 401(k) Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis.

The 401(k) Plan provides either a Company Matching Contribution or a Non-Elective Safe Harbor Contribution for all eligible participants. Certain eligible participants receive a Company Retirement Contribution based on the participant's age and years of service or a Company Discretionary Contribution, depending upon the pension plan in which the employee participates. Vesting of all Company contributions ranges from immediate vesting to graduated vesting at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

Defined Benefit Pension Plan (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.

The Pension Plan assets are held in a Master Trust. Due to the plan merger on December 31, 2016, reporting beginning in 2017 no longer represents an undivided interest in the Master Trust. Our Board of Directors has approved the Pension Plan's 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 Plan's 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 Pension Plan's benefit payment obligations. The Pension Plan's 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, 2017, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 37% to 45% equity securities and 55% to 63% fixed-income liability-hedging assets and the expected rate of return from these asset categories.

The expected long-term rate of return for investments was 6.25% and 6.75% for the Pension Plan 2017 and 2016 plan years, respectively. Our Pension Plan is funded in compliance with the federal government's funding requirements.

<u>Plan Assets</u>

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

	2017	2016
Equity securities	26%	28%
Real estate	4	5
Fixed income funds	63	57
Cash and cash equivalents	1	2
Hedge funds	6	8
Total	100%	100%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are not funded by the Company.

<u>Plan Assets</u>

We do not fund our Supplemental Plans. We fund on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plans

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. Pre-65 retirees receive their retiree medical benefits through the Black Hills self-insured retiree medical plans. Healthcare coverage for Medicare-eligible BHP retirees is provided through an individual market healthcare exchange. 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

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. 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):

	2017	2016
Defined Benefit Plans		
Defined Benefit Pension Plan	$ 4,000	$ 820
Non-Pension Defined Benefit Postretirement Healthcare Plans	$ 348	$ 420
Supplemental Non-qualified Defined Benefit Plan	$ 246	$ 221
Defined Contribution Plans		
Company Retirement Contribution	$ 861	$ 851
Matching Contributions	$ 1,306	$ 1,400

While we do not have required contributions, we expect to make approximately $1.8 million in contributions to our Defined Benefit Pension Plan in 2018.

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. The Company's 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 (in thousands):

Pension Plan	December 31, 2017					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total

	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total
AXA Equitable General Fixed Income	$ —	$ 184	$ —	$ 184	$ —	$ 184
Common Collective Trust - Cash and Cash Equivalents	—	314	—	314	—	314
Common Collective Trust - Equity	—	15,749	—	15,749	—	15,749
Common Collective Trust - Fixed Income	—	37,732	—	37,732	—	37,732
Common Collective Trust - Real Estate	—	249	—	249	2,258	2,507
Hedge Funds	—	—	—	—	3,398	3,398
Total investments measured at fair value	$ —	$ 54,228	$ —	$ 54,228	$ 5,656	$ 59,884

Pension Plan

	December 31, 2016					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total
AXA Equitable General Fixed Income	$ —	$ 196	$ —	$ 196	$ —	$ 196
Common Collective Trust - Cash and Cash Equivalents	—	784	—	784	—	784
Common Collective Trust - Equity	—	14,927	—	14,927	—	14,927
Common Collective Trust - Fixed Income	—	31,003	—	31,003	—	31,003
Common Collective Trust - Real Estate	—	347	—	347	2,300	2,647
Hedge Funds	—	—	—	—	4,331	4,331
Total investments measured at fair value	$ —	$ 47,257	$ —	$ 47,257	$ 6,631	$ 53,888

(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 plan's benefit obligations and fair value of plan assets above.

AXA Equitable General Fixed Income Fund: This fund is a diversified portfolio, 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 of loans with similar characteristics. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair value 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 value 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. The Plan's investments in the AXA Equitable General Fixed Income Fund are categorized as Level 2.

Common Collective Trust Funds: These funds are valued based upon the redemption price of units held by the Plan, which is based on the current fair value of the common collective trust funds' underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. 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. The funds without participant withdrawal limitations are categorized as Level 2.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance.

Common Collective Trust-Real Estate Fund: This is the same fund as above except that certain of the funds' assets contain participant withdrawal policies with restrictions on redemption and are therefore not included in the fair value hierarchy.

Hedge Funds: These 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.

Other Plan Information

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the Consolidated Balance Sheets, components of the net periodic expense and elements of AOCI (in thousands):

Benefit Obligations

As of December 31,	Defined Benefit		Supplemental Non-qualified		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 64,973	$ 65,959	$ 3,404	$ 3,426	$ 5,843	$ 6,208
Service cost	545	606	—	—	206	204
Interest cost	2,341	2,499	116	122	176	187
Actuarial loss (gain)	4,008	455	144	78	130	(446)
Benefits paid	(3,445)	(3,215)	(246)	(222)	(348)	(420)
Plan participants transfer to affiliate	(860)	(1,331)	—	—	(137)	(31)
Plan participants' contributions	—	—	—	—	100	141
Projected benefit obligation at end of year	$ 67,562	$ 64,973	$ 3,418	$ 3,404	$ 5,970	$ 5,843

Employee Benefit Plan Assets

	Defined Benefit		Supplemental Non-qualified		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Beginning fair value of plan assets	$ 53,888	$ 54,723	$ —	$ —	$ —	$ —
Investment income (loss)	6,150	2,485	—	—	—	—
Benefits paid	(3,445)	(3,215)	(246)	(221)	(348)	(420)
Participant contributions	—	—	—	—	100	141
Employer contributions	4,000	820	246	221	248	279

Plan participants transfer to affiliate	(709)	(925)	—	—	—	—
Ending fair value of plan assets	$ 59,884	$ 53,888	$ —	$ —	$ —	$ —

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

	Defined Benefit		Supplemental Non-qualified		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Regulatory asset (liability)	$ 18,998	$ 18,974	$ —	$ —	$ (1,758)	$ (2,087)
Current liability	$ —	$ —	$ (245)	$ (247)	$ (534)	$ (541)
Non-current liability	$ (7,676)	$ (11,085)	$ (3,173)	$ (3,157)	$ (5,436)	$ (5,302)

Accumulated Benefit Obligation

As of December 31 (in thousands)	Defined Benefit		Supplemental		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Accumulated benefit obligation (a)	$ 64,782	$ 61,585	$ 3,418	$ 3,404	$ 5,970	$ 5,843

(a) The Defined Benefit Pension Plan Accumulated Benefit Obligation for 2017 and 2016 represents the obligation for the merged Black Hills Retirement Plan.

Components of Net Periodic Expense

Net periodic expense consisted of the following for the year ended December 31 (in thousands):

	Defined Benefit			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Service cost	$ 545	$ 606	$ 797	$ —	$ —	$ —	$ 206	$ 204	$ 233
Interest cost	2,341	2,499	2,956	116	122	142	176	187	214
Expected return on assets	(3,591)	(3,632)	(3,935)	—	—	—	—	—	—
Amortization of prior service cost (credits)	43	43	43	—	—	—	(336)	(337)	(336)
Recognized net actuarial loss (gain)	1,230	1,995	2,196	87	82	93	—	—	—
Net periodic expense	$ 568	$ 1,511	$ 2,057	$ 203	$ 204	$ 235	$ 46	$ 54	$ 111

AOCI

For defined benefit plans, 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		Supplemental Non-qualified		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2017	2016	2017	2016	2017	2016
Net (gain) loss	$ —	$ —	$ 707	$ 669	$ —	$ —
Total AOCI	$ —	$ —	$ 707	$ 669	$ —	$ —

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 2018 are as follows (in thousands):

	Defined Benefits	Supplemental Non-qualified	Non-pension Defined Benefit Postretirement Healthcare Plan
Net gain (loss)	$ 1,341	$ 67	$ —
Prior service cost	28	—	(218)
Total net periodic benefit cost expected to be recognized during calendar year 2018	$ 1,369	$ 67	$ (218)

Assumptions

	Defined Benefit			Supplemental Non-qualified			Non-pension Defined Benefit Postretirement Healthcare Plan		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Weighted-average assumptions used to determine benefit obligations:									
Discount rate	3.71%	4.27%	4.63%	3.62%	4.12%	4.29%	3.60%	3.84%	4.03%
Rate of increase in compensation levels	3.43%	3.47%	3.57%	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)	4.27%	4.63%	4.25%	4.12%	4.29%	3.98%	3.84%	4.03%	3.70%
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	3.47%	3.57%	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 3.71% for the calculation of the 2018 net periodic pension costs.
(b) The expected rate of return on plan assets is 6.25% for the calculation of the 2018 net periodic pension cost.

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

	2017	2016
Trend Rate - Medical		
Pre-65 for next year	7.00%	6.10%
Pre-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2027	2024
Post-65 for next year	5.00%	5.10%
Post-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2026	2023

We do not pre-fund our supplemental plan or our healthcare plan. The table below shows the expected impacts of an increase or decrease to our healthcare trend rate for our Healthcare Plan (in thousands):

Change in Assumed Trend Rate	Accumulated Periodic Postretirement Benefit Obligation	Service and Interest Costs
Increase 1%	$ 186	$ 7
Decrease 1%	$ (174)	$ (7)

Beginning in 2016, we 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. 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	Supplemental Non-qualified	Defined Benefit Postretirement Healthcare Plan
2018	$ 3,489	$ 245	$ 534
2019	$ 3,628	$ 242	$ 621
2020	$ 3,725	$ 239	$ 633
2021	$ 3,835	$ 333	$ 613
2022	$ 3,964	$ 329	$ 592
2023-2027	$ 20,648	$ 1,417	$ 2,479

(9) RELATED-PARTY TRANSACTIONS

Non-Cash Dividend to Parent

We recorded non-cash dividends to our Parent of approximately $42 million and $53 million in 2017 and 2016 respectively, and decreased the utility Money pool note receivable for approximately $42 million and $53 million in 2017 and 2016, 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):

		2017	2016
Receivable - affiliates	$	5,664 $	9,526
Accounts payable - affiliates	$	25,653 $	31,799

Money Pool Notes Receivable and Notes Payable

On September 1, 2017, the Utility Money Pool was transferred from Black Hills Power to our affiliate Black Hills Utility Holdings. This transfer reduced our cash by $0.7 million, reduced our Money pool notes receivable, net by $1.0 million and increased our Retained earnings by $0.3 million.

We will continue to participate in the Utility Money Pool Agreement (the Agreement). Under the Agreement, we may borrow from the pool; however the Agreement restricts the pool from loaning funds to BHC or to any of BHC's non-utility subsidiaries. The Agreement does not restrict us from paying 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 plus 1.0%.

The cost of borrowing under the Utility Money Pool was 1.96% at December 31, 2017.

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

		2017	2016
Notes receivable (payable)	$	(13,487)$	28,365

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

		2017	2016
Interest income	$	272 $	1,047 $

Interest expense allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2017 and 2016, we were allocated $1.4 million and $1.9 millionn, respectively, of interest expense 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:

	(in thousands)	
	2017	2016
Revenues:		
Energy sold to Cheyenne Light	$ 2,481	$ 2,440
Rent from electric properties	$ 5,100	$ 5,046
Fuel and purchased power:		
Purchases of coal from WRDC	$ 15,948	$ 16,227
Purchase of excess energy from Cheyenne Light	$ 601	$ 252
Purchase of renewable wind energy from Cheyenne Light - Happy Jack	$ 1,924	$ 1,918
Purchase of renewable wind energy from Cheyenne Light - Silver Sage	$ 3,290	$ 3,300
Gas transportation service agreement:		
Gas transportation service agreement with Cheyenne Light for firm and interruptible gas transportation	$ 393	$ 399
Corporate support:		
Corporate support services and fees from Parent, Black Hills Service Company and Black Hills Utility Holdings	$ 27,869	$ 25,748

Horizon Point Agreement

We have an arrangement among South Dakota Electric, Black Hills Service Company, and Black Hills Utility Holdings where there is a cost allocation for the use of the Horizon Point facility that is owned by South Dakota Electric. This cost allocation, includes the recovery of and return on allocable property and recovery of incurred administrative service expenses for the operation and maintenance of the Horizon Point facility.

(10) SUPPLEMENTAL CASH FLOW INFORMATION

	(in thousands)	
Years ended December 31,	2017	2016
Non-cash investing and financing activities -		

Property, plant and equipment acquired with accrued liabilities	$	6,565	$	5,521	$
Non-cash decrease to money pool note receivable	$	(42,000)	$	(52,500)	$
Non-cash dividend to Parent company	$	42,000	$	52,500	$
Cash (paid) refunded during the period for -					
Interest (net of amounts capitalized)	$	(21,517)	$	(21,320)	$
Income taxes (paid) refunded	$	(12,719)	$	—	$

(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, 2017 (see Note 9 for information on related party agreements):

- A PPA with PacifiCorp, expiring December 31, 2023, for the purchase 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 service agreement with PacifiCorp that expires December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.
- An agreement with Thunder Creek for gas transport capacity, expiring October 31, 2019.

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

Contract	Contract Type		2017		2016
PacifiCorp	Electric capacity and energy	$	13,218	$	12,221
PacifiCorp	Transmission access	$	1,671	$	1,428
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):

2018	$	13,531
2019	$	6,839
2020	$	6,839
2021	$	6,206
2022	$	6,206
Thereafter	$	6,206

Long-Term Power Sales Agreements

We have the following power sales agreements as of December 31, 2017:

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU. This agreement expires January 31, 2023.

- An agreement to serve MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023.

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, which expires September 3, 2019, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.

- 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 (assigned to Macquarie on January 3, 2018) expiring December 31, 2021 to supply 50 MW of energy during heavy and light load timing intervals.

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.

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 following the closure certification date.

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.

For additional information on environmental matters, see Item 1 in this Annual Report on Form 10-K.

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 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 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.

(12) SUBSEQUENT EVENTS

Management has evaluated and concluded that there were no significant subsequent events occurring after December 31, 2017 to February 26, 2018, 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, 2018. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.