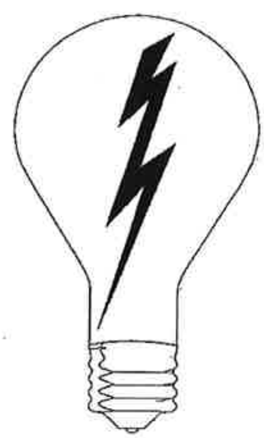
YEAR ENDING 2015

ANNUAL REPORT
OF
Black Hills Power
d/b/a Black Hills Energy

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

Table of Contents

Description	Schedule
Instructions	
Identification	1
Board of Directors	2
Officers	3
Corporate Structure	4
Corporate Allocations	5
Affiliate Transactions - To the Utility	6
Affiliate Transactions - By the Utility	7
Montana Utility Income Statement	8
Montana Revenues	9
Montana Operation and Maintenance Expenses	10
Montana Taxes Other Than Income	11
Payments for Services	12
Political Action Committees/Political Contrib.	13
Pension Costs	14
Other Post Employment Benefits	15
Top Ten Montana Compensated Employees	16
Top Five Corporate Compensated Employees	17
Balance Sheet	18

continued on next page

Description	Schedule
Montana Plant in Service	19
Montana Depreciation Summary	20
Montana Materials and Supplies	21
Montana Regulatory Capital Structure	22
Statement of Cash Flows	23
Long Term Debt	24
Preferred Stock	25
Common Stock	26
Montana Earned Rate of Return	27
Montana Composite Statistics	28
Montana Customer Information	29
Montana Employee Counts	30
Montana Construction Budget	31
Peak and Energy	32
Sources and Disposition of Energy	33
Sources of Electric Supply	34
MT Conservation and Demand Side Mgmt. Programs	35
Electrical Universal Systems Benefits Programs	35a
MT Conservation and Demand Side Management Programs	35b
Montana Consumption and Revenues	36

IDENTIFICATION

Year: 2015

1.	Legal Name of Respondent:	Black Hills Power, Inc
2.	Name Under Which Respondent Does Business:	Black Hills Energy
3.	Date Utility Service First Offered in Montana	2/23/1968
4.	Address to send Correspondence Concerning Report:	625 Ninth Street Rapid City, SD 57702
5.	Person Responsible for This Report:	Jon Thurber Manager, Regulatory Services
5a.	Telephone Number:	605-721-1603

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:

1a. Name and address of the controlling organization or person:	Black Hills Corporation 625 Ninth Street, Rapid City, SD 57701
1b. Means by which control was held:	Common Stock
1c. Percent Ownership:	100%

SCHEDULE 2

Board of Directors

Line No.	Name of Director and Address (City, State) (a)		Remuneration (b)
1	David R. Emery	Rapid City, SD	$0.00 (c)
2	Jack W. Eugster (a)	Excelsior, MN	$7,500.00
3	Michael H. Madison (a)	Shreveport, LA	$6,180.00
4	Linda K. Massman (a)	Spokane, WA	$0.00
5	Steven R. Mills (a)	Monticello, IL	$6,944.00
6	Stephen D. Newlin (a)	Scottsdale, AZ	$7,291.00
7	Gary L. Pechota (a)	Hills City, SD	$6,875.00
8	Rebecca B. Roberts (a)	The Woodlands, TX	$7,083.00
9	Warren L. Robinson (a)	Rapid City, SD	$7,291.00
10	John B. Vering (a)	Southlake, TX	$6,180.00
11	Thomas J. Zeller (a)	Rapid City, SD	$8,333.00
12	Linden R. Evans (b)	Rapid City, SD	$0.00 (c)
13	Steven J. Helmers (b)	Rapid City, SD	$0.00 (c)
14	Richard W. Kinzley (b)	Rapid City, SD	$0.00 (c)
15			
16	(a) Resigned effective January 28, 2015		
17	(b) Appointed effective January 28, 2015		
18	(c) As officers of the company they receive no compensation for their services as directors.		
19			
20			

Officers

Year: 2015

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman & Chief Executive Officer		David R. Emery
2	President & Chief Operating Officer		Linden R. Evans
3	Executive Vice President		Anthony S. Cleberg (a)
4	Sr. Vice President & Chief Financial Officer		Richard W. Kinzley (b)
5	Sr. Vice President, General Counsel & Chief Compliance Officer		Steven J. Helmers
6	Sr. Vice President - Chief Human Resources Officer		Robert A. Myers
7	Sr. Vice President - Chief Information Officer		Scott A. Buchholz
8	Sr. Vice President-Regulatory & Govt Affairs, Asst General Counsel		Brian G. Iverson
9	Vice President - Governance & Corporate Secretary		Roxann R. Basham
10	Vice President - Supply Chain		Perry S. Krush
11	Vice President - Corporate Controller		Esther J. Newbrough (c)
12	Vice President - Treasurer		Kimberly F. Nooney (d)
13	Vice President - Regulatory Affairs		Kyle D. White
14	Vice President - Strategic Planning & Development		Jeffrey B. Berzina
15	Vice President - Utility Operations		Stuart A. Wevik
16	Vice President - Operations Services		Ivan Vancas
17	Vice President and General Manager - Power Delivery		Mark L. Lux
18	Vice President - BHP Operations		Vance Crocker
19	Vice President - Energy Asset Optimization		Richard C. Loomis
20	Vice President - Corporate Affairs		Stephen L. Pella (e)
21	Vice President - Customer Service		Randy D. Winkelman (f)

(a) Anthony S. Cleberg's title changed to Executive Vice President on January 1, 2015, and he retired on April 1, 2015.

(b) Richard W. Kinzley was promoted to Senior Vice President & Chief Financial Officer on January 1, 2015.

(c) Esther J. Newbrough was promoted to Vice President - Corporate Controller on January 5, 2015.

(d) Kimberly F. Nooney was promoted to Vice President - Treasurer on January 5, 2015.

(e) Stephen L. Pella, Vice President - Corporate Affairs, retired on June 30, 2015. His responsibilities were disbursed to other officers and the position was eliminated.

(f) Randy D. Winkelman, Vice President - Customer Service, retired on June 30, 2015; his position is vacant.

CORPORATE STRUCTURE

Year: 2015

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc	Electric Utility	45,173,711	100.00%
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42				100.00%
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49				
50	**TOTAL**		45,173,711	

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

CORPORATE ALLOCATIONS

Year: 2015

	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: 2015

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)	12,243,400	18.82%	677,276
2	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	5,214,954	3.47%	288,479
3	Black Hills Service Company	Information Technology, General Accounting, Insurance, Regulatory and Governmental Services, Facilities, Various Other Non-Power Goods and Services	Black Hills Service Company Cost Allocation Manual	25,008,405	44.29%	1,383,405
4	Black Hills Utility Holding Company	Various Non-power Good and Services	Black Hills Utility Holdings Company Cost Allocation Manual	13,487,234	44.73%	746,082
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24	**TOTAL**			55,953,993		3,095,242

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2015

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	1,036,764	100.00%	
2	Black Hills Wyoming	Transmission Services	Point to Point Open Access Transmission Tariff	105,135	100.00%	
3	Cheyenne Light Fuel and Power	Transmission Services	Point to Point Open Access Transmission Tariff Fair Market Value	2,774,247	3.60%	153,465
4	Black Hills Wyoming	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	15,122	100.00%	
5	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	1,857,435	2.41%	102,749
6	Black Hills Colorado Electric	Generation Dispatch	Fair Market Value (based on similar arms-length transactions	1,058,476	0.77%	58,552
7	Cheyenne Light Fuel and Power	Neil Simpson Complex	Fair Market Value (based on similar arms-length transactions	7,883,183	10.23%	436,079
8	Cheyenne Light Fuel and Power	Environmental Complex	Fair Market Value (based on similar arms-length transactions	72,297	0.09%	3,999
9	Cheyenne Light Fuel and Power	Generation Dispatch	Fair Market Value (based on similar arms-length transactions	933,009	1.21%	51,612
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22	**TOTAL**			15,735,668		806,456

MONTANA UTILITY INCOME STATEMENT

Year: 2015

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	268,032,559	277,396,391	3.49%
2				
3	Operating Expenses			
4	401 Operation Expenses	149,327,775	136,129,741	-8.84%
5	402 Maintenance Expense	14,149,653	14,579,237	3.04%
6	403 Depreciation Expense	28,564,785	30,704,553	7.49%
7	404-405 Amortization of Electric Plant	437,477	1,749,909	300.00%
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	6,089,010	6,210,180	1.99%
12	409.1 Income Taxes - Federal	278,153	14,079,653	4961.84%
13	- Other	90		-100.00%
14	410.1 Provision for Deferred Income Taxes	35,295,900	33,053,195	-6.35%
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	(19,227,106)	(25,114,217)	-30.62%
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**	215,013,143	211,489,657	-1.64%
21	**NET UTILITY OPERATING INCOME**	53,019,416	65,906,734	24.31%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Electricity			
2	440 Residential	6,077	6,233	2.57%
3	442 Commercial & Industrial - Small	28,762	22,650	-21.25%
4	Commercial & Industrial - Large	4,589,381	6,957,684	51.60%
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**	4,624,220	6,986,567	51.09%
11	447 Sales for Resale			
12				
13	**TOTAL Sales of Electricity**	4,624,220	6,986,567	51.09%
14	449.1 (Less) Provision for Rate Refunds			
15				
16	**TOTAL Revenue Net of Provision for Refunds**	4,624,220	6,986,567	51.09%
17	Other Operating Revenues			
18	450 Forfeited Discounts & Late Payment Revenues	4,893	30	-99.39%
19	451 Miscellaneous Service Revenues	7	15	114.29%
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**	4,900	45	-99.09%
26	**Total Electric Operating Revenues**	4,629,120	6,986,612	50.93%

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

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2015

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	1,255,893	734,402	-41.52%
6	501 Fuel	18,934,285	20,058,106	5.94%
7	502 Steam Expenses	3,348,185	1,688,286	-49.58%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	758,352	815,567	7.54%
11	506 Miscellaneous Steam Power Expenses	988,006	1,411,625	42.88%
12	507 Rents	2,465,706	2,256,931	-8.47%
13				
14	TOTAL Operation - Steam	27,750,427	26,964,917	-2.83%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	1,392,079	1,238,903	-11.00%
18	511 Maintenance of Structures	625,760	474,943	-24.10%
19	512 Maintenance of Boiler Plant	3,646,173	4,442,261	21.83%
20	513 Maintenance of Electric Plant	1,107,383	850,038	-23.24%
21	514 Maintenance of Miscellaneous Steam Plant	114,669	78,563	-31.49%
22				
23	TOTAL Maintenance - Steam	6,886,064	7,084,708	2.88%
24				
25	**TOTAL Steam Power Production Expenses**	34,636,491	34,049,625	-1.69%
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: 2015

	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	436,279	1,167,396	167.58%
27	547	Fuel	4,013,048	3,835,791	-4.42%
28	548	Generation Expenses	617,509	605,667	-1.92%
29	549	Miscellaneous Other Power Gen. Expenses	120,476	478,561	297.23%
30	550	Rents	228,570	272,737	19.32%
31					
32		TOTAL Operation - Other	5,415,882	6,360,152	17.44%
33					
34	Maintenance				
35	551	Maintenance Supervision & Engineering	95,290	83,635	-12.23%
36	552	Maintenance of Structures	4,271	4,160	-2.60%
37	553	Maintenance of Generating & Electric Plant	699,640	1,224,317	74.99%
38	554	Maintenance of Misc. Other Power Gen. Plant	63,111	91,811	45.48%
39					
40		TOTAL Maintenance - Other	862,312	1,403,923	62.81%
41					
42		**TOTAL Other Power Production Expenses**	6,278,194	7,764,075	23.67%
43					
44	Other Power Supply Expenses				
45	555	Purchased Power	52,114,368	43,019,391	-17.45%
46	556	System Control & Load Dispatching	1,633,798	1,660,770	1.65%
47	557	Other Expenses	1,626	35,432	2079.09%
48					
49		TOTAL Other Power Supply Expenses	53,749,792	44,715,593	-16.81%
50					
51		**TOTAL Power Production Expenses**	94,664,477	86,529,293	-8.59%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2015

	Account Number & Title		Last Year	This Year	% Change
1	Transmission Expenses				
2	Operation				
3	560	Operation Supervision & Engineering	728,633	1,077,849	47.93%
4	561	Load Dispatching	2,565,712	2,568,967	0.13%
5	562	Station Expenses	258,509	261,170	1.03%
6	563	Overhead Line Expenses	53,623	69,154	28.96%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	20,068,338	19,065,613	-5.00%
9	566	Miscellaneous Transmission Expenses	438,304	102,690	-76.57%
10	567	Rents			
11					
12	TOTAL Operation - Transmission		24,113,119	23,145,443	-4.01%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	(30)	1,918	6493.33%
15	569	Maintenance of Structures	13,943		-100.00%
16	570	Maintenance of Station Equipment	134,635	190,231	41.29%
17	571	Maintenance of Overhead Lines	31,397	123,359	292.90%
18	572	Maintenance of Underground Lines	567		-100.00%
19	573	Maintenance of Misc. Transmission Plant	564	2,664	372.34%
20					
21	TOTAL Maintenance - Transmission		181,076	318,172	75.71%
22					
23	**TOTAL Transmission Expenses**		24,294,195	23,463,615	-3.42%
24					
25	Distribution Expenses				
26	Operation				
27	580	Operation Supervision & Engineering	1,350,961	1,275,678	-5.57%
28	581	Load Dispatching	434,787	479,227	10.22%
29	582	Station Expenses	580,082	685,838	18.23%
30	583	Overhead Line Expenses	530,039	381,647	-28.00%
31	584	Underground Line Expenses	265,997	276,511	3.95%
32	585	Street Lighting & Signal System Expenses	9,728	536	-94.49%
33	586	Meter Expenses	768,006	912,253	18.78%
34	587	Customer Installations Expenses	9,352	8,612	-7.91%
35	588	Miscellaneous Distribution Expenses	900,284	1,096,523	21.80%
36	589	Rents	8,052	16,986	110.95%
37					
38	TOTAL Operation - Distribution		4,857,288	5,133,811	5.69%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	2,387	173	-92.75%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	449,802	182,882	-59.34%
43	593	Maintenance of Overhead Lines	3,456,304	3,453,411	-0.08%
44	594	Maintenance of Underground Lines	300,968	360,400	19.75%
45	595	Maintenance of Line Transformers	83,265	43,530	-47.72%
46	596	Maintenance of Street Lighting, Signal Systems	148,385	225,105	51.70%
47	597	Maintenance of Meters	165,385	119,870	-27.52%
48	598	Maintenance of Miscellaneous Dist. Plant	350,637	96,250	-72.55%
49					
50	TOTAL Maintenance - Distribution		4,957,133	4,481,621	-9.59%
51					
52	**TOTAL Distribution Expenses**		9,814,421	9,615,432	-2.03%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2015

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	67,164	49,314	-26.58%
4	902 Meter Reading Expenses	10,787	6,029	-44.11%
5	903 Customer Records & Collection Expenses	2,085,651	2,125,488	1.91%
6	904 Uncollectible Accounts Expenses	417,434	316,409	-24.20%
7	905 Miscellaneous Customer Accounts Expenses	670,327	742,089	10.71%
8				
9	TOTAL Customer Accounts Expenses	3,251,363	3,239,329	-0.37%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	166,943	196,482	17.69%
14	908 Customer Assistance Expenses	1,294,259	1,446,134	11.73%
15	909 Informational & Instructional Adv. Expenses	24,760	18,065	-27.04%
16	910 Miscellaneous Customer Service & Info. Exp.	50,170	55,944	11.51%
17				
18	TOTAL Customer Service & Info Expenses	1,536,132	1,716,625	11.75%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision	427		-100.00%
23	912 Demonstrating & Selling Expenses	24,817	3,704	-85.07%
24	913 Advertising Expenses	119		-100.00%
25	916 Miscellaneous Sales Expenses	95		-100.00%
26				
27	TOTAL Sales Expenses	25,458	3,704	-85.45%
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	18,027,527	14,217,986	-21.13%
32	921 Office Supplies & Expenses	3,813,393	3,162,635	-17.07%
33	922 (Less) Administrative Expenses Transferred - Cr.	(971,745)	(786,276)	19.09%
34	923 Outside Services Employed	2,598,842	2,364,140	-9.03%
35	924 Property Insurance	667,449	823,556	23.39%
36	925 Injuries & Damages	1,880,147	1,687,289	-10.26%
37	926 Employee Pensions & Benefits	(77,019)	968,632	1357.65%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	857,466	781,281	-8.88%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	312,738	299,028	-4.38%
42	930.2 Miscellaneous General Expenses	967,458	717,010	-25.89%
43	931 Rents	552,059	614,887	11.38%
44				
45	TOTAL Operation - Admin. & General	28,628,315	24,850,168	-13.20%
46	Maintenance			
47	935 Maintenance of General Plant	1,263,067	1,290,812	2.20%
48				
49	**TOTAL Administrative & General Expenses**	29,891,382	26,140,980	-12.55%
50				
51	**TOTAL Operation & Maintenance Expenses**	163,477,428	150,708,978	-7.81%

MONTANA TAXES OTHER THAN INCOME

Year: 2015

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	4,947	6,186	25.05%
5	Montana PSC	16,214	14,574	-10.11%
6	Franchise Taxes			
7	Property Taxes	271,154	214,429	-20.92%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	10,362	16,653	60.71%
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50				
51	**TOTAL MT Taxes Other Than Income**	302,677	251,842	-16.80%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2015

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Amounts to Montana are not significant				
2					
3					
4					
5					
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47					
48					
49					
50	**TOTAL Payments for Services**				

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2015

	Description	Total Company	Montana	% Montana
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
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48				
49				
50	**TOTAL Contributions**			

Pension Costs

Year: 2015

1	Plan Name: Pension Plan of Black Hills Corporation			
2	Defined Benefit Plan? ___YES_________________ Defined Contribution Plan? No			
3	Actuarial Cost Method? Project Unit Credit Method IRS Code: ____401b____________			
4	Annual Contribution by Employer: -0- 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	71,177,890	60,223,264	-15.39%
8	Service cost	796,738	703,744	-11.67%
9	Interest Cost	2,955,602	2,991,380	1.21%
10	Plan participants' contributions			
11	Amendments			
12	Actuarial Gain	(5,687,038)	11,711,671	305.94%
13	Acquisition			
14	Benefits paid	(3,284,063)	(4,452,169)	-35.57%
15	Benefit obligation at end of year	65,959,129	71,177,890	7.91%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	59,097,785	56,404,827	-4.56%
18	Actual return on plan assets	(1,090,388)	5,449,127	599.74%
19	Acquisition			
20	Employer contribution	-	1,696,000	
21	Plan participants' contributions	-	-	
22	Benefits paid	(3,284,063)	(4,452,169)	-35.57%
23	Fair value of plan assets at end of year	54,723,334	59,097,785	7.99%
24	**Funded Status**	(11,235,795)	(12,080,105)	-7.51%
25	Unrecognized net actuarial loss	19,678,169	22,536,432	14.53%
26	Unrecognized prior service cost	137,893	180,521	30.91%
27	Prepaid (accrued) benefit cost	8,580,267	10,636,848	23.97%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	4.63%	4.25%	-8.21%
31	Expected return on plan assets	6.75%	6.75%	
32	Rate of compensation increase	3.57%	3.86%	8.12%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	796,738	703,744	-11.67%
36	Interest cost	2,955,602	2,991,380	1.21%
37	Expected return on plan assets	(3,934,608)	(3,701,853)	5.92%
38	Amortization of prior service cost	42,628	42,628	
39	Recognized net actuarial loss	2,196,221	940,223	-57.19%
40	Net periodic benefit cost	2,056,581	976,122	-52.54%
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	492	516	4.88%
48	Not Covered by the Plan			
49	Active	210	232	10.48%
50	Retired	215	209	-2.79%
51	Deferred Vested Terminated	67	75	11.94%

Other Post Employment Benefits (OPEBS)

Year: 2015

	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	4.03%	3.70%	-8.19%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	5.78%	6.88%	19.03%
10	Actuarial Cost Method			
11	Rate of compensation increase	3.57%	4.00%	12.04%
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13				
14				
15	**Describe any Changes to the Benefit Plan:**			
16				
17	**TOTAL COMPANY**			
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year	6,037,834	5,849,907	-3.11%
20	Service cost	233,125	222,202	-4.69%
21	Interest Cost	213,886	241,435	12.88%
22	Plan participants' contributions	119,624	88,587	-25.95%
23	Amendments		-	
24	Actuarial Gain	(9,498)	123,569	1401.00%
25	Acquisition			
26	Benefits paid	(386,665)	(487,866)	-26.17%
27	Benefit obligation at end of year	6,208,306	6,037,834	-2.75%
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	267,041	399,279	49.52%
33	Plan participants' contributions	119,624	88,587	-25.95%
34	Benefits paid	(386,665)	(487,866)	-26.17%
35	Fair value of plan assets at end of year	-	-	
36	**Funded Status**	(6,208,306)	(6,037,834)	2.75%
37	Unrecognized net actuarial loss	(2,521,960)	551,406	121.86%
38	Unrecognized prior service cost	572,042	(2,857,699)	-599.56%
39	Prepaid (accrued) benefit cost	(8,158,224)	(8,344,127)	-2.28%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	233,125	222,202	-4.69%
42	Interest cost	213,886	241,435	12.88%
43	Expected return on plan assets		-	
44	Amortization of prior service cost	-335739	(335,739)	
45	Recognized net actuarial loss			
46	Net periodic benefit cost	111,272	127,898	14.94%
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: 2015

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	439	429	-2.28%
3	Not Covered by the Plan			
4	Active	270	264	-2.22%
5	Retired	88	83	-5.68%
6	Spouses/Dependants covered by the Plan	81	82	1.23%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost			
11	Interest Cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost			
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ___________________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

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

SCHEDULE 17

Year: 2015

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, President and Chief Executive Officer						
2	Richard W. Kinzley Sr. Vice President and Chief Financial Officer						
3	Linden R. Evans Chief Operating Officer - Utilities						
4	Steven J. Helmers Sr. Vice President and General Corporate Counsel						
5	Robert A. Myers Sr. Vice President Human Resources						

* 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, 2015, 2014 and 2013. 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	2015	$738,333	$1,425,200	$613,241	$1,283,749	$70,979	$4,131,502
Chairman, President and Chief Executive	2014	$715,500	$1,347,931	$1,177,092	$2,782,449	$63,661	$6,086,633
Officer	2013	$689,650	$1,037,511	$996,155	$—	$64,294	$2,787,610
Richard W. Kinzley(1) Sr. Vice President and Chief Financial Officer	2015	$326,241	$254,490	$151,520	$—	$160,404	$892,655
Linden R. Evans	2015	$462,833	$458,081	$277,556	$—	$356,843	$1,555,313
Chief Operating Officer – Utilities	2014	$448,500	$419,911	$533,688	$113,452	$305,840	$1,821,391
	2013	$428,481	$399,050	$446,992	$—	$308,013	$1,582,536
Steven J. Helmers	2015	$351,500	$285,020	$146,698	$176,119	$139,826	$1,099,163
Sr. Vice President – General Counsel	2014	$331,333	$285,178	$272,775	$404,197	$121,391	$1,414,874
	2013	$316,300	$269,349	$228,444	$—	$112,303	$926,396
Robert A. Myers	2015	$328,833	$229,015	$136,368	$—	$175,427	$869,643
Sr. Vice President – Human Resources	2014	$321,500	$233,278	$234,764	$—	$195,545	$985,087
	2013	$312,219	$219,468	$200,442	$—	$192,092	$924,221

(1) Mr. Kinzley was named Sr. Vice President and Chief Financial Officer effective January 1, 2015.

(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. 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, 2015.

(3) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2015 awards at its January 26, 2016 meeting, and the awards were paid on February 26, 2016.

(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, 2015. 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 much volatility in the last three years with a large increase in values in 2014 and negative values for Messrs. Kinzley and Evans in 2015 and all Named Executive Officers in 2013. The large change in pension value for 2014 was due to implementation of new mortality tables and the change in discount rates used to calculate the present value of these benefits. A value of zero is shown in the Summary Compensation Table for certain officers in 2015 and 2013 because the SEC does not allow a negative number to be disclosed in the table.

The Pension Plan and PRB were frozen effective January 1, 2010 for participants who did not satisfy the age 45 and 10 years of service eligibility. Messrs. Kinzley, Evans and Helmers did not meet the eligibility choice criteria and their

BALANCE SHEET

Year: 2015

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	990,213,637	1,115,816,370	-11%
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	1,080,454	1,066,689	1%
8	106 Completed Constr. Not Classified - Electric	113,531,560	16,737,023	578%
9	107 Construction Work in Progress - Electric	9,915,812	32,186,367	-69%
10	108 (Less) Accumulated Depreciation	(346,500,576)	(365,331,725)	5%
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.	(3,326,741)	(3,424,147)	3%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	769,784,454	801,920,885	-4%
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	4,606,955	4,733,684	-3%
23	125 Sinking Funds			
24	**TOTAL Other Property & Investments**	4,606,955	4,733,684	-3%
25				
26	**Current & Accrued Assets**			
27	131 Cash	6,615,917	7,556,333	-12%
28	132-134 Special Deposits			
29	135 Working Funds	4,100	3,075	33%
30	136 Temporary Cash Investments			
31	141 Notes Receivable	13,361	13,905	-4%
32	142 Customer Accounts Receivable	15,754,901	13,963,871	13%
33	143 Other Accounts Receivable	9,404,293	40,397,559	-77%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(261,000)	(206,608)	-26%
35	145 Notes Receivable - Associated Companies	68,777,957	76,829,006	-10%
36	146 Accounts Receivable - Associated Companies	5,350,054	5,746,964	-7%
37	151 Fuel Stock	6,117,565	4,943,559	24%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	14,124,903	17,709,660	-20%
41	155 Merchandise			
42	156 Other Material & Supplies			
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed	674,997	1,612,613	-58%
45	165 Prepayments	4,427,880	3,481,482	27%
46	171 Interest & Dividends Receivable			
47	172 Rents Receivable			
48	173 Accrued Utility Revenues	9,998,584	12,795,081	-22%
49	174 Miscellaneous Current & Accrued Assets	47,179	16,163	192%
50	**TOTAL Current & Accrued Assets**	141,050,691	184,862,663	-24%

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

BALANCE SHEET

Year: 2015

	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	3,275,101	3,139,878	4%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
8a	182.3	Other Regulatory Assets	76,273,004	83,504,808	
9	183	Prelim. Survey & Investigation Charges	8,410,523	144,063	5738%
10	184	Clearing Accounts	558,660	763,517	-27%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	34,701	212,135	-84%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	2,376,577	2,095,690	13%
16	190	Accumulated Deferred Income Taxes	33,629,868	30,565,748	10%
17		**TOTAL Deferred Debits**	124,558,434	120,425,839	3%
18					
19		**TOTAL Assets & Other Debits**	1,040,000,534	1,111,943,071	-6%
	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	313,621,617	330,295,328	-5%
35	217	(Less) Reacquired Capital Stock	(1,818,661)	(1,306,744)	-39%
36		**TOTAL Proprietary Capital**	374,794,281	391,979,909	-4%
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.	(102,810)	(98,670)	-4%
46		**TOTAL Long Term Debt**	342,752,190	342,756,330	0%

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

BALANCE SHEET

Year: 2015

	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	562,455	668,005	-16%
9	228.3	Accumulated Provision for Pensions & Benefits			
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	3,073,081	94	3269135%
12		**TOTAL Other Noncurrent Liabilities**	3,635,536	668,099	444%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	29,687,267	20,505,363	45%
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies	19,242,062	30,031,809	-36%
20	235	Customer Deposits	1,133,255	1,199,082	-5%
21	236	Taxes Accrued	5,200,222	18,508,667	-72%
22	237	Interest Accrued	4,814,131	4,615,398	4%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	1,038,910	994,424	4%
27	242	Miscellaneous Current & Accrued Liabilities	4,605,367	44,169,053	-90%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	65,721,214	120,023,796	-45%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	1,017,219	1,175,968	-13%
34	253	Other Deferred Credits	21,735,442	21,183,042	3%
34a	254	Other Regulatory Liabilities	16,406,014	13,452,047	
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	213,938,638	220,703,880	-3%
39		**TOTAL Deferred Credits**	253,097,313	256,514,937	-1%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		1,040,000,534	1,111,943,071	-6%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2015

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

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2015

	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	4,965	(4,805)	203%
36	362	Station Equipment	(405,041)	(454,255)	11%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	416,967	431,386	-3%
39	365	Overhead Conductors & Devices	442,033	481,159	-8%
40	366	Underground Conduit	6,081	226	2591%
41	367	Underground Conductors & Devices	13,144	13,144	
42	368	Line Transformers	79,768	62,681	27%
43	369	Services	8,109	8,109	
44	370	Meters	1,276	856	49%
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49		**TOTAL Distribution Plant**	593,606	564,805	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2015

	Account Number & Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment			
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment			
12	397 Communication Equipment	425	425	
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	425	425	
17				
18	**TOTAL Electric Plant in Service**	594,031	565,230	

MONTANA DEPRECIATION SUMMARY

Year: 2015

	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	564,805	950,541	945,957	
8	General	425	228	220	
9	**TOTAL**	565,230	950,769	946,177	

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		53.35%		
13	Preferred Stock				
14	Long Term Debt		46.65%		
15	Other				
16	**TOTAL**		100.00%		

STATEMENT OF CASH FLOWS

Year: 2015

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	33,561,612	45,173,711	-26%
6	Depreciation	29,099,668	32,551,868	-11%
7	Amortization			
8	Deferred Income Taxes - Net	16,068,794	7,938,978	102%
9	Investment Tax Credit Adjustments - Net			
10	Change in Operating Receivables - Net	(9,409,420)	(1,419,330)	-563%
11	Change in Materials, Supplies & Inventories - Net	(34,141)	(218,079)	84%
12	Change in Operating Payables & Accrued Liabilities - Net	10,828,606	21,402,670	-49%
13	Allowance for Funds Used During Construction (AFUDC)	(518,985)	(918,580)	44%
14	Change in Other Assets & Liabilities - Net	(2,482,371)	(11,589,477)	79%
15	Other Operating Activities (explained on attached page)	(10,278,063)	1,629,610	-731%
16	**Net Cash Provided by/(Used in) Operating Activities**	66,835,700	94,551,371	-29%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(82,826,462)	(56,795,507)	-46%
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	(51,333,516)	(36,687,182)	-40%
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	(153,873)	(127,272)	-21%
27	**Net Cash Provided by/(Used in) Investing Activities**	(134,313,851)	(93,609,961)	-43%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	72,800,000		
32	Preferred Stock			
33	Common Stock			
34	Other:			
35	Net Increase in Short-Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt			
39	Preferred Stock			
40	Common Stock			
41	Other:	(960,798)	(2,019)	
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**	71,839,202	(2,019)	3558258%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	4,361,051	939,391	364%
49	**Cash and Cash Equivalents at Beginning of Year**	2,258,966	6,620,017	-66%
50	**Cash and Cash Equivalents at End of Year**	6,620,017	7,559,408	-12%

Attachment 23A **Year: 2015**

Footnotes for Statement of Cash Flow

Line 15, Current year - Other Operating Activities includes:

$	2,403,208	employee benefit plans
$	486,601	amortization
$	(518,812)	regulatory assets and liabilities
$	(278,194)	other current and non-current assets
$	(463,193)	other deferred credits non-current
$	1,629,610	

Line 15, Last year - Other Operating Activities includes:

$	(1,911,899)	employee benefit plans
$	(1,696,000)	benefit plan contribution
$	448,332	amortization of deferred finance costs
$	(5,364,039)	other current and non-current assets
$	(1,754,457)	other deferred credits non-current
$	(10,278,063)	

Line 26, Current year - Other Investing Activities

$	(127,272)	primary decrease in cash surrender value for PEP insurance

Line 26, Last year - Other Investing Activities

$	153,873	primary decrease in cash surrender value for PEP insurance

Line 41, Current year - Other Financing Activities

$	(2,019)	deferrred financing costs

Line 41, Last year - Other Financing Activities

$	(960,798)	deferrred financing costs

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

SCHEDULE 24

LONG TERM DEBT

Year: 2015

	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 Improvement Bonds	06/94	06/24	2,855,000	2,855,000	2,855,000	0.75%	21,413	0.75%
8									
9									
10	Line 7, 1994 A EI Bonds have a variable interest rate. The weighted average rate for 2015 was 0.75%								
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			342,855,000	342,730,800	342,855,000		20,435,776	5.96%

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

PREFERRED STOCK

Year: 2015

	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										
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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: 2015

		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: 2015

	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 complete because			
32	Montana revenues represents less than			
33	3.5% 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: 2015

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	565
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	(946)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	(381)
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	6,987
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	6,987
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	6,987
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	12
36		Commercial	23
37		Industrial	5
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	40
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	69,642
45		Average Annual Residential Cost per (Kwh) (Cents) *	8
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	519
48		Gross Plant per Customer	(9.53)

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

SCHEDULE 29

MONTANA CUSTOMER INFORMATION

Year: 2015

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Carter and Powder River Counties	2,953	12	23	5	40
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
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29						
30						
31						
32	**TOTAL Montana Customers**	2,953	12	23	5	40

MONTANA EMPLOYEE COUNTS

Year: 2015

	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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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: 2016

	Project Description	Total Company	Total Montana
1			
2			
3			
4			
5			
6			
7			
8			
9			
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46			
47			
48			
49			
50	**TOTAL**		

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2015

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	8	1800	391	288,768	83,009
2	Feb.	27	800	376	255,103	79,819
3	Mar.	3	2200	366	266,042	82,810
4	Apr.	9	900	308	256,405	86,185
5	May	19	2100	309	243,170	80,748
6	Jun.	29	1700	401	255,721	79,280
7	Jul.	23	1700	407	256,146	54,369
8	Aug.	14	1500	424	250,644	53,575
9	Sep.	2	1600	305	216,347	46,271
10	Oct.	29	800	312	211,803	30,738
11	Nov.	30	2000	367	255,796	63,640
12	Dec.	29	1800	369	239,778	96,676
13	**TOTAL**				2,995,723	837,120

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	1,537,744	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,775,358
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	80,944	for Resale	128,168
7	(Less) Energy for Pumping			
8	**NET Generation**	1,618,688	Non-Requirements Sales	
9	Purchases	1,422,017	for Resale	969,845
10	Power Exchanges			
11	Received	10,275	Energy Furnished	
12	Delivered	55,257	Without Charge	
13	**NET Exchanges**	(44,982)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	7,286,231	Electric Utility	167,333
16	Delivered	7,286,231		
17	**NET Transmission Wheeling**	-	Total Energy Losses	(44,981)
18	Transmission by Others Losses			
19	**TOTAL**	2,995,723	**TOTAL**	2,995,723

SOURCES OF ELECTRIC SUPPLY

Year: 2015

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	80	1,968
2					
3	Thermal	Ben French	Rapid City, SD	10	-333
4					
5	Thermal	Wyodak	Gillette, WY	69	533,264
6					
7	Thermal	Neil Simpson II	Gillette, WY	84	602,999
8					
9	Thermal	Lange	Rapid City, SD	39	10,862
10					
11	Thermal	Neil Simpson CT	Gillette, WY	39	8,223
12					
13	Thermal	Wygen III	Gillette, WY	57	401,460
14					
15	Combined Cycle	Cheyenne Prairie	Cheyenne, WY	55	60,189
16					
17	Purchase	See Schedule 32			1,422,017
18					
19	Wheeling	See Schedule 32			
20					
21	Total Interchange	See Schedule 32			(44,982)
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**			433	2,995,667

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 35**

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2015

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1	N/A						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
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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: 2015

	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	$6,233	$6,077	77	73	12	11
2	Commercial - Small	22,650	28,762	215	261	23	23
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	6,957,684	4,589,381	110,761	72,961	5	5
6	Interruptible Industrial						
7	Public Street & Highway Lighting						
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities						
11	Interdepartmental						
12							
13	**TOTAL**	$6,986,567	$4,624,220	111053	73295	40	39

The following pages are the notes to the financial statements as reported in FERC FORM 1 2015 for Black Hills Power, Inc.

NOTES TO FINANCIAL STATEMENTS
December 31, 2015, 2014 and 2013

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc. (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 requirements differ from GAAP related to the presentation of certain items including deferred income taxes, and cost of removal liabilities. The Company's notes to the financial statements are prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of the Company's FERC basis financial statements contained herein.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash Equivalents

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

Regulatory Accounting

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

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

Regulatory assets are included in Regulatory assets, current and Regulatory assets, non-current on the accompanying Balance Sheets. Regulatory liabilities are included in Regulatory liabilities, current and Regulatory liabilities, non-current on the accompanying Balance Sheets.

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

	Maximum Recovery Period (in years)	2015	2014
Regulatory assets:			
Unamortized loss on reacquired debt [(a)]	9	$ 2,096	$ 2,377
AFUDC[(b)]	45	8,571	8,365
Employee benefit plans[(c)]	12	20,866	24,418
Deferred energy costs[(a)]	1	19,875	14,696
Flow through accounting[(a)]	35	12,104	11,171
Decommissioning costs [(b)]	9	13,686	11,786
Other regulatory assets[(a) (d)]	2	8,615	5,871
Total regulatory assets		$ 85,813	$ 78,684
Regulatory liabilities:			
Cost of removal for utility plant[(a)]	53	$ 38,131	$ 35,510
Employee benefit plans[(c)]	12	12,616	14,538
Other regulatory liabilities[(c)]	13	836	4,941
Total regulatory liabilities		$ 51,583	$ 54,989

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

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

Unamortized Loss on Reacquired Debt - The early redemption premium on reacquired bonds is being amortized over the remaining term of the original bonds.

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

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

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

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

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

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

Cost of Removal for Utility Plant - Cost of removal for utility plant represents the estimated cumulative net provisions for future removal costs included in depreciation expense for which there is no legal obligation for removal.

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

Accounts Receivable and Allowance for Doubtful Accounts

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

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

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

	2015	2014
Accounts receivable trade	$ 15,268	$ 24,946
Unbilled revenues	12,795	9,999
Allowance for doubtful accounts	(207)	(261)
Net accounts receivable trade	$ 27,856	$ 34,684

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price, delivery has occurred or services have been rendered, and collectibility is reasonably assured. 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, we accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month, and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Receivables-customers, net on the accompanying Balance Sheets.

Materials, Supplies and Fuel

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

Other Current Assets

The following amounts by major classification are included in Other current assets on the accompanying Balance Sheets as of (in thousands):

	December 31, 2015	December 31, 2014
Accrued receivables related to litigation expenses and settlements	$ 39,050	$ —
Other (none of which is individually significant)	4,068	4,954
Total other current assets	$ 43,118	$ 4,954

Accrued Liabilities

The following amounts by major classification are included in Accrued liabilities on the accompanying Balance Sheets as of (in thousands):

	December 31, 2015	December 31, 2014
Accrued employee compensation, benefits and withholdings	$ 5,054	$ 4,689
Accrued property taxes	4,962	4,721
Accrued payments related to litigation expenses and settlements	38,750	—
Accrued income taxes	13,031	—
Customer deposits and prepayments	2,216	1,934
Accrued interest	4,600	4,662
Other (none of which is individually significant)	841	409
Total accrued liabilities	$ 69,454	$ 16,415

Deferred Financing Costs

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

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost when placed in service. Included in the cost of regulated construction projects is AFUDC, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage, is charged to accumulated depreciation. Removal costs associated with non-legal obligations are reclassified from accumulated depreciation and reflected as regulatory liabilities. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Depreciation provisions for regulated electric property, plant and equipment are computed on a straight-line basis using an annual composite rate of 2.3% in 2015, 2.3% in 2014 and 2.1% in 2013.

Derivatives and Hedging Activities

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

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

Revenues and expenses on contracts that qualify are designated as normal purchases and normal sales and are recognized when the underlying physical transaction is completed under the accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it was determined that a transaction designated as a normal purchase or normal sale no longer met the exceptions, the fair value of the related contract would be reflected as either an asset or liability, under the accounting standards for derivatives and hedging.

Fair Value Measurements

Accounting standards for fair value measurements provide a single definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date and also requires disclosures and establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values giving the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

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

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

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

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

Impairment of Long-Lived Assets

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

Income Taxes

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

We use the asset and liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. At December 31, 2015, we have chosen to early adopt on a prospective basis ASU 2015-17 as discussed below under Recently Issued and Adopted Accounting Standards. As of December 31, 2015, we classify all deferred tax assets and liabilities as non-current. The prior period is presented under the previous guidance for classifying deferred tax assets and deferred tax liabilities as current and non-current.

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

We account for uncertainty in income taxes recognized in the financial statements in accordance with accounting standards for income taxes. The unrecognized tax benefit is classified in Other - non-current liabilities on the accompanying Balance Sheets. See Note 6 for additional information.

Recently Issued and Adopted Accounting Principles

<u>Balance Sheet Classification of Deferred Taxes, ASU 2015-17</u>

In November 2015, the FASB issued ASU 2015-17 providing guidance on financial statement presentation for deferred tax assets and deferred tax liabilities. All deferred taxes are to be presented as non-current. FASB issued this guidance as part of its initiative to reduce complexity in accounting standards. This guidance is effective for fiscal years beginning after December 15, 2016, including interim periods within those years (i.e., in the first quarter of 2017 for calendar year-end companies). The guidance may be applied either prospectively, for all deferred tax assets and liabilities, or retrospectively by reclassifying the comparative balance sheets. Early adoption is permitted. We have chosen early adoption as of December 31, 2015, on a prospective basis. At December 31, 2015, the balance sheet reflects a net non-current deferred tax liability of $189 million. The balance sheet presentation as of December 31, 2014 was not adjusted retrospectively and remains as previously reported with a net current deferred tax asset of $14 million and a non-current deferred tax liability of $193 million.

Simplifying the Presentation of Debt Issuance Costs, ASU 2015-03

In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. Debt issuance costs related to a recognized debt liability will be presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts, rather than as an asset. Amortization of these costs will continue to be reported as interest expense. ASU 2015-03 is effective for annual and interim reporting periods beginning after December 15, 2015. Early adoption is permitted. We have chosen not to early adopt ASU 2015-03.

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. The guidance also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows from an entity's contracts with customers. On July 9, 2015, FASB voted to defer the effective date of ASU 2014-09 by one year. The guidance would be effective for annual and interim reporting periods beginning after December 15, 2018 and early adoption is permitted. We are currently assessing the impact that adoption of ASU 2014-09 will have on our financial position, results of operations or cash flows.

(2) PROPERTY, PLANT AND EQUIPMENT

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

	2015	2015 Weighted Average Useful Life (in years)	2014	2014 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Maximum
Electric plant:						
Production	$ 569,182	46	$ 567,936	48	40	65
Transmission	117,708	48	115,949	46	40	60
Distribution	353,241	46	336,652	39	20	60
Plant acquisition adjustment (a)	4,870	32	4,870	32	32	32
General	88,939	22	79,738	22	5	40
Total plant-in-service	1,133,940		1,105,145			
Construction work in progress	32,186		9,916			
Total electric plant	1,166,126		1,115,061			
Less accumulated depreciation and amortization	(326,074)		(309,767)			
Electric plant net of accumulated depreciation and amortization	$ 840,052		$ 805,294			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 15 years remaining.

(3) JOINTLY OWNED FACILITIES

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

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

- We own a 35% interest in, and are the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the transmission tie is 400 MW - 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. Cheyenne Light owns the remaining 40 MW. This facility was placed into commercial operations on October 1, 2014. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

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

As of December 31, 2015, our interests in jointly-owned generating facilities and transmission systems included on our Balance Sheets were as follows (in thousands):

Interest in jointly-owned facilities	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$ 111,532	$ 1,039	$ 56,812
Transmission Tie	$ 19,648	$ —	$ 5,390
Wygen III	$ 137,860	$ 446	$ 16,217
Cheyenne Prairie	$ 91,081	$ —	$ 3,301

(4) LONG-TERM DEBT

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

	Maturity Date	Interest Rate	2015	2014
First Mortgage Bonds due 2032	August 15, 2032	7.23%	$ 75,000	$ 75,000
First Mortgage Bonds due 2039	November 1, 2039	6.125%	180,000	180,000
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
Unamortized discount, First Mortgage Bonds due 2039			(99)	(103)
Series 94A Debt (a)	June 1, 2024	0.75%	2,855	2,855
Long-term debt			$ 342,756	$ 342,752

(a) Variable interest rate at December 31, 2015.

On October 1, 2014 we issued $85 million of 4.43% coupon first mortgage bonds due October 20, 2044. Proceeds from our bond sale funded the early redemption of our 5.35% $12 million pollution control revenue bonds, originally due October 1, 2024.

Net deferred financing costs of approximately $3.1 million and $3.3 million were recorded on the accompanying Balance Sheets in Other, non-current assets at December 31, 2015 and 2014, respectively, and are being amortized over the term of the debt. Amortization of deferred financing costs of approximately $0.1 million, $0.1 million and $0.1 million for the years ended December 31, 2015, 2014 and 2013, respectively, are included in Interest expense on the accompanying Statements of Income.

Substantially all of our property is subject to the lien of the indenture securing our first mortgage bonds. First mortgage bonds may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. We were in compliance with our debt covenants at December 31, 2015.

Long-term Debt Maturities

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

2016	$	—
2017	$	—
2018	$	—
2019	$	—
2020	$	—
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):

	2015		2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents (a)	$ 7,559	$ 7,559	$ 6,620	$ 6,620
Long-term debt, including current maturities (b)	$ 342,756	$ 404,864	$ 342,752	$ 430,497

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

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

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

Cash and Cash Equivalents

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

(6) INCOME TAXES

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

	2015	2014	2013
Current	$ 14,910	$ (6)	$ (163)
Deferred	7,690	16,518	13,582
Total income tax expense	$ 22,600	$ 16,512	$ 13,419

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

	2015	2014
Deferred tax assets:		
Employee benefits	$ 4,683	$ 4,995
Net operating loss	15	14,794
Regulatory liabilities	9,908	10,824
Other	16,171	2,864
Total deferred tax assets	30,777	33,477
Deferred tax liabilities:		
Accelerated depreciation and other plant related differences	(187,666)	(184,478)
AFUDC	(8,571)	(8,365)
Regulatory assets	(4,236)	(3,910)
Employee benefits	(3,003)	(3,723)
Deferred costs	(14,765)	(11,324)
Other	(1,497)	(1,058)
Total deferred tax liabilities	(219,738)	(212,858)
Net deferred tax assets (liabilities)	$ (188,961)	$ (179,381)

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

	2015	2014	2013
Federal statutory rate	35.0%	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.1)	(0.3)	(0.3)
Equity AFUDC	(0.6)	(0.1)	—
Flow through adjustments (a)	(0.9)	(1.9)	(2.5)
Tax credits	—	(0.2)	(0.8)
Other	—	0.5	(0.6)
	33.4%	33.0%	30.8%

(a) The flow-through adjustments relate primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred during 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit consistent with the flow through method.

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

	2015	2014
Unrecognized tax benefits at January 1	$ 1,623	$ 2,443
Additions for prior year tax positions	888	434
Reductions for prior year tax positions	(247)	(1,254)
Additions for current year tax positions	—	—
Unrecognized tax benefits at December 31	$ 2,264	$ 1,623

The reductions for prior year tax positions relate to the reversal through otherwise allowed tax depreciation. The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.7 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the years ended December 31, 2015 and 2014, the interest expense recognized was not material to our financial results.

In January 2016, the Company reached an agreement in principle with IRS Appeals with respect to research and development tax credits and deductions for tax years 2007 through 2009, and expect a reduction of approximately $0.4 million with respect to our liability for unrecognized tax benefits on or before December 31, 2016.

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

At December 31, 2015, we are no longer in a federal NOL carry forward position.

(7) COMPREHENSIVE INCOME

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

	Derivatives Designated as Cash Flow Hedges	Amounts Reclassified from AOCI	
		2015	2014
Gains and Losses on cash flow hedges			
Interest rate swaps gain (loss)	Interest expense	$ 64	$ 64
Income tax	Income tax benefit (expense)	319	(364)
Total reclassification adjustments related to cash flow hedges, net of tax		$ 383	$ (300)
Amortization of defined benefit plans:			
Actuarial gain (loss)	Operations and maintenance	$ 94	$ 45
Income tax	Income tax benefit (expense)	(33)	(16)
Total reclassification adjustments related to defined benefit plans, net of tax		$ 61	$ 29

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, 2014	$ (1,018)	$ (801)	$ (1,819)
Other comprehensive income (loss)	383	129	512
As of December 31, 2015	$ (635)	$ (672)	$ (1,307)

	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2013	$ (719)	$ (478)	$ (1,197)
Other comprehensive income (loss)	(299)	(323)	(622)
As of December 31, 2014	$ (1,018)	$ (801)	$ (1,819)

(8) EMPLOYEE BENEFIT PLANS

Funded Status of Benefit Plans

The funded status of the postretirement benefit plan is required to be recognized in the statement of financial position. The funded status for the pension plan is measured as the difference between the projected benefit obligation and the fair value of plan assets. The funded status for all other benefit plans is measured as the difference between the accumulated benefit obligation and the fair value of plan assets. A liability is recorded for an amount by which the benefit obligation exceeds the fair value of plan assets or an asset is recorded for any amount by which the fair value of plan assets exceeds the benefit obligation. The measurement date of the plans is December 31, our year-end balance sheet date. As of December 31, 2015, the unfunded status of our Defined Benefit Pension Plan was $11 million, the unfunded status of our Supplemental Non-qualified Defined Benefit Plans was $3.4 million and the unfunded status of our Non-pension Defined Benefit Postretirement Healthcare Plans was $6.2 million.

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

Defined Benefit Pension Plan

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

Pension Plan assets are held in a Master Trust that was established for the investment of assets of the Plan and other Employer-sponsored retirement plans. Each participating retirement plan has an undivided interest in the Master Trust.
The BHC Board of Directors have approved the Plans' investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plans' beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Plans' benefit payment obligations. The Pension Plans' assets consist primarily of equity, fixed income and hedged investments. The expected long-term rate of return for investments was 6.75% and 6.75% for the 2015 and 2014 plan years, respectively. Our Pension Plan funding policy is in accordance with the federal government's funding requirements.

Pension Plan Assets

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

	2015	2014
Equity securities	26%	27%
Real estate	5	5
Fixed income funds	59	58
Cash and cash equivalents	1	2
Hedge funds	9	8
Total	100%	100%

Supplemental Non-qualified Defined Benefit Retirement Plans

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

Supplemental Plan Assets

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

Non-pension Defined Benefit Postretirement Healthcare Plan

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

Plan Assets

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

Plan Contributions and Estimated Cash Flows

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

	2015	2014
Defined Benefit Plans		
Defined Benefit Pension Plan	$ —	$ 1,696
Non-pension Defined Benefit Postretirement Healthcare Plan	$ 267	$ 399
Supplemental Non-qualified Defined Benefit Plan	$ 211	$ 217
Defined Contribution Plans		
Company Retirement Contribution	$ 811	$ 638
Matching Contributions	$ 1,423	$ 1,377

Although we are not required we expect to contribute approximately $1.6 million to our Defined Benefit Pension Plan in 2016.

Fair Value Measurements

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

Defined Benefit Pension Plan		**2015**		
	Level 1	Level 2	Level 3	Total Fair Value
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 498	$ —	$ 498
Common Collective Trust - Equity	—	14,198	—	14,198
Common Collective Trust - Fixed Income	—	32,615	—	32,615
Common Collective Trust - Real Estate	—	418	2,113	2,531
Hedge Funds	—	—	4,881	4,881
Total investments measured at fair value	$ —	$ 47,729	$ 6,994	$ 54,723

Defined Benefit Pension Plan		**2014**		
	Level 1	Level 2	Level 3	Total Fair Value
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 899	$ —	$ 899
Common Collective Trust - Equity	—	16,107	—	16,107
Common Collective Trust - Fixed Income	—	34,474	—	34,474
Common Collective Trust - Real Estate	—	761	1,918	2,679
Hedge Funds	—	—	4,939	4,939
Total investments measured at fair value	$ —	$ 52,241	$ 6,857	$ 59,098

Cash and Cash Equivalents: This category is comprised of the AXA Equitable General Fixed Income Fund and Common Collective Trusts - cash and cash equivalents. The AXA Equitable General Fixed Income Fund is a fund of diversified portfolios, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately place 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 at which loans with similar characteristics have. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair 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.

Common Collective Trust: 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. Certain of the funds' assets contain participant withdrawal policy and, therefore, are categorized as Level 3. The funds without participant withdrawal limitations are categorized as Level 2.

Hedge Funds: Hedge funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. Generally, shares may be redeemed at the end of each quarter with a 65 day notice and are limited to a percentage of total net asset value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds. The Plan's investment in the hedge fund is categorized as Level 3.

The following table sets forth a summary of changes in the fair value of the Defined Benefit Pension Plans' Level 3 assets for the period ended December 31 (in thousands):

	2015
Balance, beginning of period	$ 6,857
Purchase	93
Unrealized gain (loss)	63
Settlements	(19)
Balance, end of period	$ 6,994

The following table presents the quantitative information about Level 3 fair value measurements (dollars in thousands):

	Fair Value at December 31, 2015	Valuation Technique	Level 3 Input	Range (Weighted) Average
Assets:				
Common Collective Trust - Real Estate (a)	$ 2,113	Market Approach	Redemption Restriction	N/A
Hedge Funds (b)	$ 4,881	Market Approach	Redemption Restriction	N/A

(a) The underlying net asset value in the Common Collective Trust - Real Estate fund is determined by appraisal of the properties held in the Trust. 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 the 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 fund does contain a participant withdrawal policy.

(b) The fair value of the Hedge Funds is determined based on pricing provided or reviewed by third-party administrator to our investment managers. While the input amounts used by the pricing vendor in determining fair value are not provided, and therefore, unavailable for our review, the asset results are reviewed and monitored to ensure the fair values are reasonable and in line with market experience in similar asset classes. Additionally, the audited financial statements of the funds are reviewed annually as they are issued.

Plan Reconciliations

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

Benefit Obligations

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2015	2014	2015	2014	2015	2014
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 71,178	$ 60,223	$ 3,599	$ 3,131	$ 6,038	$ 5,850
Service cost	797	704	—	—	233	222
Interest cost	2,956	2,991	142	146	214	241
Actuarial loss (gain)	(5,650)	11,879	(104)	540	27	115
Benefits paid	(3,284)	(4,452)	(211)	(218)	(387)	(488)
Asset transfer (to) from affiliate	(38)	(167)	—	—	(7)	24
Medicare Part D adjustment	—	—	—	—	(30)	(15)
Plan participants' contributions	—	—	—	—	120	89
Projected benefit obligation at end of year	$ 65,959	$ 71,178	$ 3,426	$ 3,599	$ 6,208	$ 6,038

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

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2015	2014	2015	2014	2015	2014
Beginning market value of plan assets	$ 59,098	$ 56,405	$ —	$ —	$ —	$ —
Investment income	(1,057)	5,462	—	—	—	—
Benefits paid	(3,284)	(4,452)	(211)	—	(387)	—
Participant contributions	—	—	—	—	120	—
Employer contributions	—	1,696	211	—	267	—
Asset transfer to affiliate	(34)	(13)	—	—	—	—
Ending market value of plan assets	$ 54,723	$ 59,098	$ —	$ —	$ —	$ —

Amounts recognized in the Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plan	
	2015	2014	2015	2014	2015	2014
Regulatory asset (liability)	$ 19,816	$ 22,717	$ —	$ —	$ (1,946)	$ 2,306
Current liability	$ —	$ —	$ (216)	$ (217)	$ (619)	$ (519)
Non-current liability	$ (11,236)	$ (12,080)	$ (3,210)	$ (3,382)	$ (5,587)	$ (5,519)

Accumulated Benefit Obligation (in thousands)

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2015	2014	2015	2014	2015	2014
Accumulated benefit obligation	$ 62,240	$ 65,699	$ 3,426	$ 3,599	$ 6,208	$ 6,038

Components of Net Periodic Expense (in thousands)

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
	2015	2014	2013	2015	2014	2013	2015	2014	2013
Service cost	$ 797	$ 704	$ 852	$ —	$ —	$ —	$ 233	$ 222	$ 216
Interest cost	2,956	2,991	2,969	142	146	133	214	241	239
Expected return on assets	(3,935)	(3,702)	(3,764)	—	—	—	—	—	—
Amortization of prior service cost (credits)	43	43	43	—	—	—	(336)	(335)	(278)
Amortization of transition obligation	—	—	2,609	—	—	—	—	—	—
Recognized net actuarial loss (gain)	2,196	940	—	93	45	66	—	—	9
Net periodic expense	$ 2,057	$ 976	$ 2,709	$ 235	$ 191	$ 199	$ 111	$ 128	$ 186

Accumulated Other Comprehensive Income (Loss)

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

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2015	2014	2015	2014	2015	2014
Net loss	$ —	$ —	$ 673	$ (801)	$ —	$ —
Prior service cost	—	—	—	—	—	—
Total accumulated other comprehensive income (loss)	$ —	$ —	$ 673	$ (801)	$ —	$ —

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 2016 are as follows (in thousands):

	Defined Benefits Pension Plan	Supplemental Non-qualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
Net gain (loss)	$ 1,297	$ 53	$ —
Prior service cost	28	—	(218)
Total net periodic benefit cost expected to be recognized during calendar year 2016	$ 1,325	$ 53	$ (218)

Assumptions

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
	2015	2014	2013	2015	2014	2013	2015	2014	2013
Weighted-average assumptions used to determine benefit obligations:									
Discount rate	4.63%	4.25%	5.10%	4.29%	3.98%	4.68%	4.03%	3.70%	4.45%
Rate of increase in compensation levels	3.57%	3.86%	3.86%	N/A	N/A	N/A	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:									
Discount rate	4.25%	5.10%	4.35%	3.98%	4.68%	3.88%	3.70%	4.45%	3.65%
Expected long-term rate of return on assets (a)	6.75%	6.75%	7.25%	N/A	N/A	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	3.86%	3.86%	3.91%	N/A	N/A	N/A	N/A	N/A	N/A

(a) The expected rate of return on plan assets is 6.75% for the calculation of the 2016 net periodic pension cost.

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

	2015	2014
Healthcare trend rate pre-65		
Trend for next year	6.35%	7.50%
Ultimate trend rate	4.50%	4.50%
Year Ultimate Trend Reached	2024	2027
Healthcare trend rate post-65		
Trend for next year	5.20%	6.25%
Ultimate trend rate	4.50%	4.50%
Year Ultimate Trend Reached	2023	2024

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

Change in Assumed Trend Rate	Service and Interest Costs	Accumulated Periodic Postretirement Benefit Obligation
1% increase	$ 10	$ 221
1% decrease	$ (1)	$ (205)

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

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

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
2016	$ 3,492	$ 216	$ 619
2017	$ 3,594	$ 248	$ 618
2018	$ 3,677	$ 246	$ 613
2019	$ 3,814	$ 243	$ 607
2020	$ 3,911	$ 240	$ 621
2021-2025	$ 21,108	$ 1,583	$ 2,841

Defined Contribution Plan

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

(9) RELATED-PARTY TRANSACTIONS

Non-Cash Dividend to Parent

In 2015, we recorded a non-cash dividend to our Parent for approximately $28.5 million and decreased the utility money pool note receivable, net for approximately $28.5 million. No amounts were recorded for 2014.

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):

	2015	2014
Receivable - affiliates	$ 5,747	$ 5,350
Accounts payable - affiliates	$ 30,032	$ 19,242

Money Pool Notes Receivable and Notes Payable

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

The cost of borrowing under the Utility Money Pool was 1.45% at December 31, 2015.

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

	2015	2014
Notes receivable (payable), net	$ 76,813	$ 68,626

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

	2015	2014	2013
Net interest income (expense)	$ 1,153	$ 304	$ 505

Other Balances and Transactions

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

- An agreement, expiring September 3, 2028, with Cheyenne Light to acquire 15 MW of the facility output from Happy Jack. Under a separate inter-company agreement expiring on September 3, 2028, Cheyenne Light has agreed to sell up to 15 MW of the facility output from Happy Jack to us.
- An agreement, expiring September 30, 2029, with Cheyenne Light to acquire 20 MW of the facility output from Silver Sage. Under a separate inter-company agreement expiring on September 30, 2029, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to us.
- A Generation Dispatch Agreement with Cheyenne Light that requires us to purchase all of Cheyenne Light's excess energy.

Related-party Gas Transportation Service Agreement

On October 1, 2014, we entered into a gas transportation service agreement with Cheyenne Light 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.

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

	2015	2014	2013
		(in thousands)	
Revenues:			
Energy sold to Cheyenne Light	$ 1,857	$ 1,894	$ 1,338
Rent from electric properties	$ 4,772	$ 4,102	$ 3,627
Purchases:			
Purchase of coal from WRDC	$ 16,401	$ 16,861	$ 18,542
Purchase of excess energy from Cheyenne Light	$ 898	$ 3,033	$ 3,640
Purchase of renewable wind energy from Cheyenne Light - Happy Jack	$ 1,578	$ 1,959	$ 1,886
Purchase of renewable wind energy from Cheyenne Light - Silver Sage	$ 2,739	$ 3,200	$ 3,207
Corporate support services from Parent, Black Hills Service Company and Black Hills Utility Holdings	$ 26,655	$ 32,332	$ 30,738

(10) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,		2015	2014	2013
		(in thousands)		
Non-cash investing and financing activities -				
Property, plant and equipment acquired with accrued liabilities	$	3,870 $	4,234 $	13,590
Non-cash decrease to money pool note receivable, net	$	(28,501)$	— $	(8,000)
Non-cash dividend to Parent company	$	28,501 $	— $	8,000
Supplemental disclosure of cash flow information:				
Cash (paid) refunded during the period for -				
Interest (net of amounts capitalized)	$	(21,913)$	(19,573)$	(19,174)
Income taxes	$	— $	— $	219

(11) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

We have the following power purchase and transmission agreements, not including related party agreements, as of December 31, 2015 (see Note 9 for information on related party agreements):

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

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

Contract	Contract Type		2015	2014	2013
PacifiCorp	Electric capacity and energy	$	13,990 $	13,943 $	13,026
PacifiCorp	Transmission access	$	1,213 $	1,227 $	1,384
Thunder Creek	Gas transport capacity	$	633 $	633 $	633

Future Contractual Obligations

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

2016	$	12,827
2017	$	12,824
2018	$	6,513
2019	$	6,408
2020	$	5,880
Thereafter	$	17,641

Long-Term Power Sales Agreements

We have the following power sales agreements as of December 31, 2015:

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

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills of Wyoming. On April 16, 2013, private landowners filed suit in the United States District Court for the District of Wyoming asserting that the fire was caused by Black Hills Power's negligent maintenance of a transmission line. The Company denied these claims. These landowners sought recovery for reclamation and rehabilitation costs, damage to fencing and other personal property, alleged injury to timber, grass or hay, livestock and related operations, and diminished value of real estate. The State of Wyoming intervened in the lawsuit, asserting claims for fire suppression costs, and similar damage claims related to state-owned lands. As of December 31, 2015, we believed that a loss associated with settlement of pending claims was probable. Accordingly, we had recorded a loss contingency liability related to these claims and a receivable for costs we believed were reimbursable and probable of recovery under our insurance coverage. In consideration of the risk and uncertainty of litigation, the Company subsequently concluded a settlement of all claims, with all parties to the litigation. On January 4, 2016, the court entered its order dismissing the litigation with prejudice. The resolution of the State and private claims did not have a material effect upon our consolidated financial condition, results of operations or cash flows.

Legal Proceedings

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

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

Environmental Matters

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

Air

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

Title IV of the Clean Air Act applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT, Lange CT, Wygen III and Wyodak plants. Title IV of the Clean Air Act created an SO_2 allowance trading program as part of the federal acid rain program. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2045.

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

Solid Waste Disposal

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

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

(12) QUARTERLY HISTORICAL DATA (Unaudited)

We operate on a calendar year basis. The following table sets forth selected unaudited historical operating results data for each quarter (in thousands):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2015				
Operating revenues	$ 70,283	$ 68,038	$ 72,111	$ 67,432
Operating income	$ 21,490	$ 21,143	$ 23,456	$ 21,825
Net income	$ 10,403	$ 10,547	$ 12,287	$ 11,937
2014				
Operating revenues	$ 71,267	$ 60,741	$ 67,729	$ 68,751
Operating income	$ 17,546	$ 13,782	$ 19,007	$ 18,779
Net income	$ 8,643	$ 6,230	$ 9,916	$ 8,773

(13) SUBSEQUENT EVENTS

Management has evaluated and concluded that there were no significant subsequent events occurring after December 31, 2015 to February 26, 2016, 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, 2016. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.