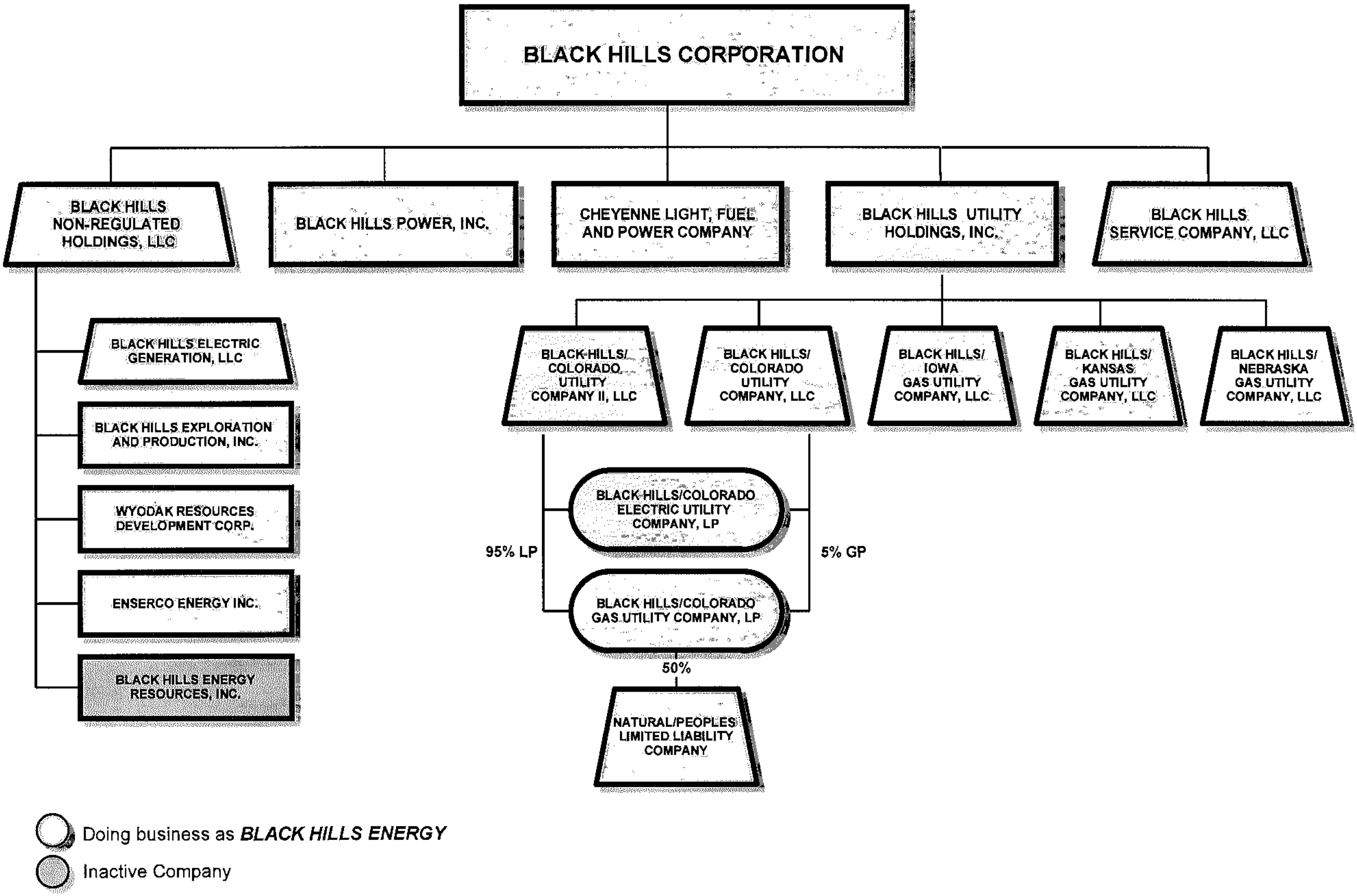
Last Update: 01/01/10

BLACK HILLS CORPORATION
ORGANIZATIONAL CHART



IDENTIFICATION

Year: 2009

1.	Legal Name of Respondent:	Black Hills Power, Inc
2.	Name Under Which Respondent Does Business:	Black Hills Power, Inc
3.	Date Utility Service First Offered in Montana	2/23/1968
4.	Address to send Correspondence Concerning Report:	625 Ninth Street- 5th Floor Rapid City, SD 57701
5.	Person Responsible for This Report:	Chris Kilpatrick Director of Rates- Electric Regulation
5a.	Telephone Number:	605-721-2748

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 (a)	Rapid City, SD	
2	Thomas J. Zeller	Rapid City, SD	$66,000
3	John R. Howard	Rapid City, SD	65,750
4	Kay S. Jorgensen	Spearfish, SD	76,000
5	David C. Ebertz	Gillette, WY	62,250
6	Gary L. Pechota	Bethlehem, PA	59,750
7	Stephen D. Newlin	Avon Lake, OH	66,000
8	Jack W. Eugster	Medina, MN	69,500
9	Warren L Robinson	Exclesior, MN	73,500
10	John B. Vering	Southlake, TX	69,750
11			
12	(a) Mr. Emery is officer of the company and is not compensated for his services		
13	as a director.		
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Officers

Year: 2009

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman & Chief Executive Officer		David R. Emery
2	President & Chief Operating Officer- Utilities		Linden R. Evans
3	Executive Vice President and CFO		Anthony S. Cleberg
4	Vice President - Governance and Corporate Secretary		Roxann R. Basham
5	Vice President - Supply Chain		Perry S. Krush
6	Vice President - Corporate Controller		Jeffrey B. Berzina
7	Vice President, Treasurer & Chief Risk Officer		Garner M. Anderson
8	Vice President - Regulatory and Governmental Affairs		Kyle D. White
9	Vice President - Strategic Planning & Development		Richard W. Kinzley
10	Vice President - Electric Utilities		Stuart A. Wevik
11	Vice President - Power Delivery		Mark L. Lux
12	Vice President and General Manager - Gillette Complex		Gregory L. Hager
13	Vice President - Customer Service		Randy D. Winkelman
14	Vice President - Operations		Richard C. Loomis
15	Vice President - Electric Regulatory Services		Brian G. Iverson
16	Senior Vice President - General Counsel and Corporate Compliance O		Steven J. Helmers
17	Senior Vice President - Chief Information Officer		Scott A. Buchholz
18	Senior Vice President - Communication and Investor Relations		Lynnette K. Wilson
19	Senior Vice President - Human Resources		Robert A. Myers
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CORPORATE STRUCTURE

Year: 2009

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	27,292,500	100.00%
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42				100.00%
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50	**TOTAL**		27,292,500	

Company Name: **Black Hills Power, Inc.** **SCHEDULE 5**

CORPORATE ALLOCATIONS

Year: 2009

	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, Inc. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY Year: 2009

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)	15,821,986	27.24%	353,938
2	Enserco Energy, Inc	Gas Sales to Utility	Fair Market Value (based on similar arms-length transactions)	2,250,176	0.06%	50,336
3	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	8,580,184	6.12%	191,939
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32	TOTAL			26,652,346		596,213

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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	980,888	100.00%	
2	Black Hills Wyoming	Transmission Service	Point to Point Open Access Transmission Tariff	617,433	100.00%	
3	Black Hills Wyoming	Non-Firm Energy Sales	Fair Market Value (Based on similar arms-length transactions)	5,152	100.00%	
4	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (Based on similar arms-length transactions)	1,823,060	2.13%	40,782
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32	TOTAL			3,426,533		40,782

BHP UTILITY INCOME STATEMENT

Year: 2009

		Account Number & Title	Last Year	This Year	% Change
1	400	Operating Revenues	228,236,534	201,802,829	-11.58%
2					
3		Operating Expenses			
4	401	Operation Expenses	153,203,703	133,917,447	-12.59%
5	402	Maintenance Expense	13,048,642	12,034,887	-7.77%
6	403	Depreciation Expense	20,778,345	19,313,360	-7.05%
7	404-405	Amortization of Electric Plant			
8	406	Amort. of Plant Acquisition Adjustments	151,404	151,404	
9	407	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Credits (SD-ECA)	(4,175,466)	(5,030,633)	-20.48%
11	408.1	Taxes Other Than Income Taxes	6,543,569	6,482,716	-0.93%
12	409.1	Income Taxes - Federal	(6,567,055)	(3,949,426)	39.86%
13		- Other		(9,843)	
14	410.1	Provision for Deferred Income Taxes	17,483,646	14,282,207	-18.31%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(1,342,539)	(2,557,392)	-90.49%
16	411.4	Investment Tax Credit Adjustments	(69,171)	(124,398)	-79.84%
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**	199,055,078	174,510,329	-12.33%
21		**NET UTILITY OPERATING INCOME**	29,181,456	27,292,500	-6.47%

MONTANA REVENUES

SCHEDULE 9

		Account Number & Title	Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	7,622	7,100	-6.85%
3	442	Commercial & Industrial - Small	64,443	72,900	13.12%
4		Commercial & Industrial - Large	2,004,360	2,237,400	11.63%
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**	2,076,425	2,317,400	11.61%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	2,076,425	2,317,400	11.61%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	2,076,425	2,317,400	11.61%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues		534	
19	451	Miscellaneous Service Revenues		8	
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**		542	
26		**Total Electric Operating Revenues**	2,076,425	2,317,942	11.63%

BHP OPERATION & MAINTENANCE EXPENSES

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	2,013,958	1,366,693	-32.14%
6	501 Fuel	19,583,103	20,400,617	4.17%
7	502 Steam Expenses	3,452,359	3,771,286	9.24%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	1,247,588	989,442	-20.69%
11	506 Miscellaneous Steam Power Expenses	1,300,972	1,270,753	-2.32%
12	507 Rents			
13				
14	TOTAL Operation - Steam	27,597,980	27,798,791	0.73%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	549,213	538,383	-1.97%
18	511 Maintenance of Structures	359,668	261,149	-27.39%
19	512 Maintenance of Boiler Plant	4,676,548	4,911,155	5.02%
20	513 Maintenance of Electric Plant	1,783,555	2,106,352	18.10%
21	514 Maintenance of Miscellaneous Steam Plant	703,605	834,242	18.57%
22				
23	TOTAL Maintenance - Steam	8,072,589	8,651,281	7.17%
24				
25	**TOTAL Steam Power Production Expenses**	35,670,569	36,450,072	2.19%
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**			

BHP OPERATION & MAINTENANCE EXPENSES

Year: 2009

	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	53,453	58,761	9.93%
27	547 Fuel	4,866,665	3,405,502	-30.02%
28	548 Generation Expenses	352,450	381,333	8.19%
29	549 Miscellaneous Other Power Gen. Expenses	35,791	39,530	10.45%
30	550 Rents			
31				
32	TOTAL Operation - Other	5,308,359	3,885,126	-26.81%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	93,202	73,522	-21.12%
36	552 Maintenance of Structures	13,625	2,995	-78.02%
37	553 Maintenance of Generating & Electric Plant	1,433,268	525,202	-63.36%
38	554 Maintenance of Misc. Other Power Gen. Plant	15,012	23,333	55.43%
39				
40	TOTAL Maintenance - Other	1,555,107	625,052	-59.81%
41				
42	**TOTAL Other Power Production Expenses**	6,863,466	4,510,178	-34.29%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	80,787,890	52,032,648	-35.59%
46	556 System Control & Load Dispatching	635,693	426,015	-32.98%
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	81,423,583	52,458,663	-35.57%
50				
51	**TOTAL Power Production Expenses**	123,957,618	93,418,913	-24.64%

BHP OPERATION & MAINTENANCE EXPENSES

Year: 2009

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	609,087	650,441	6.79%
4	561	Load Dispatching	656,647	1,152,222	75.47%
5	562	Station Expenses	62,497	51,207	-18.06%
6	563	Overhead Line Expenses	2,503	4,384	75.15%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	9,466,585	16,436,790	73.63%
9	566	Miscellaneous Transmission Expenses	201,431	172,752	-14.24%
10	567	Rents			
11					
12		TOTAL Operation - Transmission	10,998,750	18,467,796	67.91%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	6,029		-100.00%
15	569	Maintenance of Structures			
16	570	Maintenance of Station Equipment	49,666	39,642	-20.18%
17	571	Maintenance of Overhead Lines	100,593	65,243	-35.14%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant			
20					
21		TOTAL Maintenance - Transmission	156,288	104,885	-32.89%
22					
23		**TOTAL Transmission Expenses**	11,155,038	18,572,681	66.50%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	943,029	927,555	-1.64%
28	581	Load Dispatching	178,703	135,669	-24.08%
29	582	Station Expenses	462,324	456,565	-1.25%
30	583	Overhead Line Expenses	533,525	772,644	44.82%
31	584	Underground Line Expenses	228,638	224,904	-1.63%
32	585	Street Lighting & Signal System Expenses	3,156	738	-76.62%
33	586	Meter Expenses	331,448	371,428	12.06%
34	587	Customer Installations Expenses	28,661	17,871	-37.65%
35	588	Miscellaneous Distribution Expenses	545,655	462,092	-15.31%
36	589	Rents	22,500	22,500	
37					
38		TOTAL Operation - Distribution	3,277,639	3,391,966	3.49%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	26,743	10,188	-61.90%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	116,827	151,137	29.37%
43	593	Maintenance of Overhead Lines	1,865,762	1,885,918	1.08%
44	594	Maintenance of Underground Lines	161,178	151,169	-6.21%
45	595	Maintenance of Line Transformers	7,885	12,849	62.95%
46	596	Maintenance of Street Lighting, Signal Systems	103,418	132,013	27.65%
47	597	Maintenance of Meters	57,737	67,682	17.22%
48	598	Maintenance of Miscellaneous Dist. Plant	41,573	44,895	7.99%
49					
50		TOTAL Maintenance - Distribution	2,381,123	2,455,851	3.14%
51					
52		**TOTAL Distribution Expenses**	5,658,762	5,847,817	3.34%

BHP OPERATION & MAINTENANCE EXPENSES

Year: 2009

	Account Number & Title		Last Year	This Year	% Change
1		Customer Accounts Expenses			
2	Operation				
3	901	Supervision	24,916	11,233	-54.92%
4	902	Meter Reading Expenses	560,035	586,848	4.79%
5	903	Customer Records & Collection Expenses	850,185	1,173,248	38.00%
6	904	Uncollectible Accounts Expenses	636,748	315,616	-50.43%
7	905	Miscellaneous Customer Accounts Expenses	629,010	565,625	-10.08%
8					
9		TOTAL Customer Accounts Expenses	2,700,894	2,652,570	-1.79%
10					
11		Customer Service & Information Expenses			
12	Operation				
13	907	Supervision	125,138	110,586	-11.63%
14	908	Customer Assistance Expenses	761,110	798,690	4.94%
15	909	Informational & Instructional Adv. Expenses	7,473	12,502	67.30%
16	910	Miscellaneous Customer Service & Info. Exp.	86,849	56,466	-34.98%
17					
18		TOTAL Customer Service & Info Expenses	980,570	978,244	-0.24%
19					
20		Sales Expenses			
21	Operation				
22	911	Supervision			
23	912	Demonstrating & Selling Expenses			
24	913	Advertising Expenses			
25	916	Miscellaneous Sales Expenses			
26					
27		TOTAL Sales Expenses			
28					
29		Administrative & General Expenses			
30	Operation				
31	920	Administrative & General Salaries	10,109,561	12,000,679	18.71%
32	921	Office Supplies & Expenses	4,951,338	4,688,341	-5.31%
33	922	(Less) Administrative Expenses Transferred - Cr.	(26,168)	(22,979)	12.19%
34	923	Outside Services Employed	1,855,011	2,411,391	29.99%
35	924	Property Insurance	678,709	526,595	-22.41%
36	925	Injuries & Damages	2,716,385	1,181,058	-56.52%
37	926	Employee Pensions & Benefits	(240,177)	1,793,377	846.69%
38	927	Franchise Requirements			
39	928	Regulatory Commission Expenses	349,007	484,022	38.69%
40	929	(Less) Duplicate Charges - Cr.			
41	930.1	General Advertising Expenses	401,255	174,910	-56.41%
42	930.2	Miscellaneous General Expenses	455,780	738,503	62.03%
43	931	Rents	300,919	308,395	2.48%
44					
45		TOTAL Operation - Admin. & General	21,551,620	24,284,292	12.68%
46	Maintenance				
47	935	Maintenance of General Plant	247,843	197,817	-20.18%
48					
49		**TOTAL Administrative & General Expenses**	21,799,463	24,482,109	12.31%
50					
51		**TOTAL Operation & Maintenance Expenses**	166,252,345	145,952,334	-12.21%

MONTANA TAXES OTHER THAN INCOME

Year: 2009

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	10,151	1,545	-84.78%
5	Montana PSC		5,698	#DIV/0!
6	Franchise Taxes			
7	Property Taxes	77,024	115,321	49.72%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	6,298	6,993	11.04%
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51	**TOTAL MT Taxes Other Than Income**	93,473	129,557	38.60%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES Year: 2009

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

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2009

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

Pension Costs

Year: 2009

1	Plan Name			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Project Unit Cost Method	IRS Code: 401b		
4	Annual Contribution by Employer: $0.00	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	51,964,624	48,937,283	-5.83%
8	Service cost	1,155,240	1,396,277	20.86%
9	Interest Cost	3,143,245	3,790,488	20.59%
10	Plan participants' contributions	-		
11	Amendments	1,026,379	(2,032,680)	-298.04%
12	Actuarial Gain	1,686,211	2,711,548	60.81%
13	Acquisition			
14	Benefits paid	(3,360,323)	(2,838,292)	15.54%
15	Benefit obligation at end of year	55,615,376	51,964,624	-6.56%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	32,100,429	52,466,274	63.44%
18	Actual return on plan assets	9,409,785	(8,770,951)	-193.21%
19	Acquisition			
20	Employer contribution			
21	Plan participants' contributions	(85,898)		100.00%
22	Benefits paid	(2,384,788)	(2,249,170)	5.69%
23	Fair value of plan assets at end of year	39,039,528	41,446,153	6.16%
24	**Funded Status**	(31,736,491)	(19,864,195)	37.41%
25	Unrecognized net actuarial loss	38,485,937	25,836,272	-32.87%
26	Unrecognized prior service cost	409,002	419,809	2.64%
27	Prepaid (accrued) benefit cost	7,158,448	6,391,886	-10.71%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	6.29%	6.35%	1.03%
31	Expected return on plan assets	8.50%	8.50%	
32	Rate of compensation increase	4.25%	4.34%	2.12%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	1,344,440	1,117,021	-16.92%
36	Interest cost	3,143,245	3,032,391	-3.53%
37	Expected return on plan assets	(2,780,274)	(4,374,194)	-57.33%
38	Amortization of prior service cost	87,030	111,947	28.63%
39	Recognized net actuarial loss	1,585,834		-100.00%
40	Net periodic benefit cost	3,380,275	(112,835)	-103.34%
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	1,257	1,027	-18.30%
48	Not Covered by the Plan	51	46	-9.80%
49	Active	840	623	-25.83%
50	Retired	183	181	-1.09%
51	Deferred Vested Terminated	183	177	-3.28%

Other Post Employment Benefits (OPEBS)

Year: 2009

	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	6.10%	6%	-1.64%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	9.00%	10.00%	11.11%
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	#VALUE!
11	Rate of compensation increase	4.25%	4.34%	2.12%
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	7,121,236	6,991,384	-1.82%
20	Service cost	376,891	216,075	-42.67%
21	Interest Cost	596,646	444,132	-25.56%
22	Plan participants' contributions	-		
23	Amendments			
24	Actuarial Gain	55,867	50,934	-8.83%
25	Acquisition			
26	Benefits paid	(172,592)	(581,289)	-236.80%
27	Benefit obligation at end of year	7,978,048	7,121,236	-10.74%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	(792,250)	(210,961)	73.37%
30	Actual return on plan assets			
31	Acquisition			
32	Employer contribution			
33	Plan participants' contributions	-	-	
34	Benefits paid	(172,592)	(581,289)	-236.80%
35	Fair value of plan assets at end of year	(964,842)	(792,250)	17.89%
36	**Funded Status**	(8,942,890)	(7,913,486)	11.51%
37	Unrecognized net actuarial loss			
38	Unrecognized prior service cost			
39	Prepaid (accrued) benefit cost	(8,942,890)	(7,913,486)	11.51%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	376,891	216,075	-42.67%
42	Interest cost	596,646	444,132	-25.56%
43	Expected return on plan assets	-	-	
44	Amortization of prior service cost			
45	Recognized net actuarial loss	55,867	50,934	-8.83%
46	Net periodic benefit cost	1,029,404	711,141	-30.92%
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	-	-	

Company Name: Black Hills Power, Inc.

SCHEDULE 15

Other Post Employment Benefits (OPEBS) Continued

Year: 2009

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	1,190	812	-31.76%
3	Not Covered by the Plan			
4	Active	996	617	-38.05%
5	Retired	102	102	
6	Spouses/Dependants covered by the Plan	92	93	1.09%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost			
11	Interest Cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost			
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ________________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

Company Name: **Black Hills Power, Inc.**

SCHEDULE 16

Year: 2009

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, Inc.**

SCHEDULE 17

Year: 2009

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	David R. Emery Chairman and Chief Executive Officer						
2	Anthony S. Clegerg Executive Vice President and Chief Financial Officer						
3	Thomas M. Ohlmacher President and Chief Operating Officer Non-regulated Energy						
4	Linden R. Evans President and Chief Operating Officer-Utilities						
5	Steven J. Helmers Senior Vice President-General Counsel and Corporate Compliance Officer						
	*PLEASE REFER TO THE EXCERPTS FROM THE BHC ANNUAL MEETING OF SHAREHOLDERS AND PROXY STATEMENT ATTACHED AS SCHEDULE 17A						

PEP and 2005 PEP. Messrs. Cleberg, Evans and Myers are the only Named Executive Officers participating in the 2007 PEP.

	Year	Defined Benefit Plan	PRB	PEP	Total Change in Pension Value
David R. Emery	2009	$ 43,690	$167,024	$151,085	$361,799
	2008	$ 33,858	$264,299	$251,573	$549,730
	2007	$ 6,366	$159,889	$146,269	$312,524
Anthony S. Cleberg	2009	$ 36,790	$ 12,762	$ 52,506	$102,058
	2008	—	$ 3,645	—	$ 3,645
Thomas M. Ohlmacher ...	2009	$131,901	$ 96,327	$ 83,791	$312,019
	2008	$101,389	$109,258	$ 82,162	$292,809
	2007	$ 36,675	$(18,858)	$ (4,172)	$ 13,645
Linden R. Evans	2009	$ 25,375	$ 24,629	$ 52,549	$102,553
	2008	$ 19,368	$ 48,132	$ 57,792	$125,292
	2007	$ 14,958	—	$ 38,994	$ 53,952
Robert A. Myers	2009	—	—	$ 28,938	$ 28,938

(4) All Other Compensation includes amounts allocated under the 401(k) match, dividends received on restricted stock and unvested restricted stock units and perquisites. Perquisites provided to our Named Executive Officers include personal use of a Company vehicle for each year and financial planning services in 2007 and 2008. Mr. Cleberg's 2008 and 2009 perquisites also include temporary living, travel and other relocation expenses, including an $89,050 loss on the sale of his home in 2009. Mr. Myers' 2009 perquisites also include temporary living, travel and relocation expenses.

	Year	401(k) Match	Dividends on Restricted Stock/Units	Relocation Expense Perquisites	Other Perquisites	Total Other Compensation
David R. Emery ..	2009	$ 7,350	$36,082	—	$8,558	$ 51,990
Anthony S. Cleberg	2009	$ 7,350	$15,913	$168,358	$7,157	$198,778
Thomas M. Ohlmacher	2009	$ 7,350	$19,313	—	$8,462	$ 35,125
Linden R. Evans ..	2009	$ 7,350	$19,521	—	$2,215	$ 29,086
Robert A. Myers ..	2009	$14,596	$ 9,755	$ 69,202	$8,437	$101,990

SUMMARY COMPENSATION TABLE

The following table sets forth the total compensation paid or earned by each of our Named Executive Officers for the fiscal years ended December 31, 2009, 2008 and 2007. We have no employment agreements with our Named Executive Officers. Messrs. Cleberg and Myers joined us on July 16, 2008 and January 1, 2009, respectively.

Name and Principal Position	Year	Salary	Stock Awards(1)	Non-Equity Incentive Plan Compensation(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(3)	All Other Compensation(4)	Total
David R. Emery	2009	$564,000	$674,723	$221,088	$361,799	$ 51,990	$1,873,600
Chairman, President	2008	$563,269	$867,400	$205,296	$549,730	$ 42,293	$2,227,988
and Chief Executive Officer	2007	$544,231	$578,930	$763,000	$312,524	$ 36,583	$2,235,268
Anthony S. Cleberg ...	2009	$315,000	$321,300	$ 79,380	$102,058	$198,778	$1,016,516
Executive Vice President and Chief Financial Officer	2008	$130,846	$225,000	$ 34,020	$ 3,645	$ 25,911	$ 419,422
Thomas M. Ohlmacher	2009	$351,000	$406,978	$ 98,280	$312,019	$ 35,125	$1,203,402
President and Chief	2008	$350,600	$466,020	$ 91,260	$292,809	$ 28,915	$1,229,604
Operating Officer— Non-regulated Energy	2007	$340,600	$366,659	$340,600	$ 13,645	$ 26,103	$1,087,607
Linden R. Evans	2009	$274,000	$406,978	$ 76,720	$102,553	$ 29,086	$ 889,337
President and Chief	2008	$273,212	$395,908	$ 71,240	$125,292	$ 24,421	$ 890,073
Operating Officer— Utilities	2007	$253,035	$230,621	$253,500	$ 53,952	$ 20,166	$ 811,274
Robert A. Myers ..... Senior Vice President Human Resources	2009	$261,322	$287,404	$ 61,600	$ 28,938	$101,990	$ 741,254

(1) Stock Awards represent the grant date fair value related to restricted stock, restricted stock units 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 11 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2009. The amount included for performance shares is based on the level the award is expected to payout. If the award were based

on the maximum payout level, the amounts for the Stock Awards column would be increased to the following amounts:

	2009	2008	2007
David R. Emery	$944,509	$1,105,450	$788,127
Anthony S. Cleberg	$449,766	$ 225,000	NA
Thomas M. Ohlmacher	$569,717	$ 616,785	$499,153
Linden R. Evans	$569,717	$ 490,714	$313,961
Robert A. Myers	$362,347	NA	NA

SEC Rule Change Impact Note: Under generally accepted accounting principles, compensation expense with respect to stock awards granted to our employees is generally recognized over the vesting periods applicable to the awards. The SEC's disclosure rules previously required that we present stock award information for 2008 and 2007 based on the amount recognized during the corresponding year for financial statement reporting purposes with respect to theses awards (which meant, in effect, that in any given year we could recognize for financial statement reporting purposes amounts with respect to grants made in that year as well as with respect to grants from past years that vested in or were still vesting during that year). However, the recent changes in the SEC disclosure rules require that we now present the stock award amounts in the applicable columns of the table above with respect to 2008 and 2007 on a similar basis as the 2009 presentation using the grant date fair value of the awards granted during the corresponding year (regardless of the period over which the awards are scheduled to vest). Since this requirement differs from the SEC's past disclosure rules, the amounts reported in the table above for stock awards in 2008 and 2007 differ from the amounts previously reported in our Summary Compensation Table for these years. As a result, to the extent applicable, each named executive officer's total compensation amount for 2008 and 2007 also differ from the amounts previously reported in our Summary Compensation Table for these years.

(2) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Annual Incentive Plan. The Compensation Committee approved the payout of the 2009 awards at its January 27, 2010, meeting and the awards were paid on March 5, 2010.

(3) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the increase in actuarial value of the Defined Benefit Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective year. The amounts for 2008 were annualized due to the change in FAS 87 measurement date. The change in present value of the accumulated benefit from September 30, 2007 to December 31, 2008 has been multiplied by 12/15ths to determine a twelve month value (except for Mr. Cleberg who did not accrue benefits for the entire 15 month period).

The PEP is offered through the Grandfathered Pension Equalization Plan ("Grandfathered PEP"), 2005 Pension Equalization Plan ("2005 PEP") and 2007 Pension Equalization Plan ("2007 PEP"). No Named Executive Officer received preferential or above-market earnings on nonqualified deferred compensation. The value attributed from each plan to each Named Executive Officer is shown in the table below. Mr. Evans was not a participant in the PRB in 2007. Messrs. Cleberg and Myers did not meet the one year service requirement to be in the Defined Benefit Plan in 2008 and 2009, respectively. Messrs. Emery and Ohlmacher are participants in the Grandfathered

PEP and 2005 PEP. Messrs. Cleberg, Evans and Myers are the only Named Executive Officers participating in the 2007 PEP.

	Year	Defined Benefit Plan	PRB	PEP	Total Change in Pension Value
David R. Emery	2009	$ 43,690	$167,024	$151,085	$361,799
	2008	$ 33,858	$264,299	$251,573	$549,730
	2007	$ 6,366	$159,889	$146,269	$312,524
Anthony S. Cleberg	2009	$ 36,790	$ 12,762	$ 52,506	$102,058
	2008	—	$ 3,645	—	$ 3,645
Thomas M. Ohlmacher	2009	$131,901	$ 96,327	$ 83,791	$312,019
	2008	$101,389	$109,258	$ 82,162	$292,809
	2007	$ 36,675	$(18,858)	$ (4,172)	$ 13,645
Linden R. Evans	2009	$ 25,375	$ 24,629	$ 52,549	$102,553
	2008	$ 19,368	$ 48,132	$ 57,792	$125,292
	2007	$ 14,958	—	$ 38,994	$ 53,952
Robert A. Myers	2009	—	—	$ 28,938	$ 28,938

(4) All Other Compensation includes amounts allocated under the 401(k) match, dividends received on restricted stock and unvested restricted stock units and perquisites. Perquisites provided to our Named Executive Officers include personal use of a Company vehicle for each year and financial planning services in 2007 and 2008. Mr. Cleberg's 2008 and 2009 perquisites also include temporary living, travel and other relocation expenses, including an $89,050 loss on the sale of his home in 2009. Mr. Myers' 2009 perquisites also include temporary living, travel and relocation expenses.

	Year	401(k) Match	Dividends on Restricted Stock/Units	Relocation Expense Perquisites	Other Perquisites	Total Other Compensation
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Anthony S. Cleberg	2009	$ 7,350	$15,913	$168,358	$7,157	$198,778
Thomas M. Ohlmacher	2009	$ 7,350	$19,313	—	$8,462	$ 35,125
Linden R. Evans	2009	$ 7,350	$19,521	—	$2,215	$ 29,086
Robert A. Myers	2009	$14,596	$ 9,755	$ 69,202	$8,437	$101,990

BALANCE SHEET

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	688,051,242	733,274,130	-6%
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			
8	106 Completed Constr. Not Classified - Electric	12,943,074	17,788,960	-27%
9	107 Construction Work in Progress - Electric	144,966,114	201,783,516	-28%
10	108 (Less) Accumulated Depreciation	(297,391,540)	(311,816,383)	5%
11	111 (Less) Accumulated Amortization			
12	114 Electric Plant Acquisition Adjustments	4,870,308	4,870,308	0%
13	115 (Less) Accum. Amort. Elec. Acq. Adj.	(2,674,807)	(2,826,211)	5%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	550,764,391	643,074,320	-14%
16				
17	**Other Property & Investments**			
18	121 Nonutility Property	5,618	5,618	
19	122 (Less) Accum. Depr. & Amort. for Nonutil. Prop.	(3,956)	(3,956)	
20	123 Investments in Associated Companies			
21	123.1 Investments in Subsidiary Companies			
22	124 Other Investments	4,146,216	4,306,695	-4%
23	125 Sinking Funds			
24	**TOTAL Other Property & Investments**	4,147,878	4,308,357	-4%
25				
26	**Current & Accrued Assets**			
27	131 Cash		1,704,765	-100%
28	132-134 Special Deposits			
29	135 Working Funds	4,175	4,175	
30	136 Temporary Cash Investments			
31	141 Notes Receivable	14,335	37,787	-62%
32	142 Customer Accounts Receivable	18,577,176	18,277,962	2%
33	143 Other Accounts Receivable	2,113,486	1,294,824	63%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(370,000)	(258,522)	-43%
35	145 Notes Receivable - Associated Companies		57,783,244	-100%
36	146 Accounts Receivable - Associated Companies	12,619,270	4,145,756	204%
37	151 Fuel Stock	7,336,132	7,127,972	3%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	11,861,073	11,675,422	2%
41	155 Merchandise			
42	156 Other Material & Supplies		100	-100%
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed	112,032	21,637	418%
45	165 Prepayments	1,308,218	1,460,374	-10%
46	171 Interest & Dividends Receivable			
47	172 Rents Receivable			
48	173 Accrued Utility Revenues	5,390,697	5,547,053	-3%
49	174 Miscellaneous Current & Accrued Assets			
50	**TOTAL Current & Accrued Assets**	58,966,594	108,822,549	-46%

BALANCE SHEET

Year: 2009

	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	1,289,597	3,419,329	-62%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	183	Prelim. Survey & Investigation Charges	1,035,817	295,878	250%
10	184	Clearing Accounts	309,222	451,166	-31%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	370,257	258,044	43%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	2,366,830	2,206,352	7%
16	190	Accumulated Deferred Income Taxes	52,085,180	51,058,199	2%
17		**TOTAL Deferred Debits**	57,456,903	57,688,968	0%
18					
19		**TOTAL Assets & Other Debits**	671,335,766	813,894,194	-18%
		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	193,281,126	216,419,980	-11%
35	217	(Less) Reacquired Capital Stock	(1,348,641)	(1,213,092)	-11%
36		**TOTAL Proprietary Capital**	254,923,810	278,198,213	-8%
37					
38	**Long Term Debt**				
39					
40	221	Bonds	129,455,000	307,499,999	-58%
41	222	(Less) Reacquired Bonds			
42	223	Advances from Associated Companies			
43	224	Other Long Term Debt	21,753,899	21,692,512	0%
44	225	Unamortized Premium on Long Term Debt			
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.		(123,510)	100%
46		**TOTAL Long Term Debt**	151,208,899	329,069,001	-54%

Company Name: Black Hills Power, Inc.

BALANCE SHEET

Year: 2009

	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			
9	228.3	Accumulated Provision for Pensions & Benefits			
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12		**TOTAL Other Noncurrent Liabilities**			
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	25,567,740	21,855,401	17%
18	233	Notes Payable to Associated Companies	70,183,866		#DIV/0!
19	234	Accounts Payable to Associated Companies	10,411,146	10,030,043	4%
20	235	Customer Deposits	669,713	669,906	0%
21	236	Taxes Accrued	4,992,767	4,380,204	14%
22	237	Interest Accrued	3,447,977	5,449,671	-37%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	999,640	2,319,164	-57%
27	242	Miscellaneous Current & Accrued Liabilities	6,307,393	6,416,568	-2%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	122,580,242	51,120,957	140%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	4,680,710	4,224,858	11%
34	253	Other Deferred Credits	35,215,645	38,262,655	-8%
35	255	Accumulated Deferred Investment Tax Credits	237,988	113,590	110%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	102,488,472	112,904,920	-9%
39		**TOTAL Deferred Credits**	142,622,815	155,506,023	-8%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		671,335,766	813,894,194	-18%

NOTES TO FINANCIAL STATEMENTS
December 31, 2009, 2008 and 2007

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc. (the Company) is an 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). Certain prior years' data presented in the financial statement have been reclassified to conform to the current year presentation. The Balance Sheet has been modified to reflect "Regulatory assets, current," which had been previously included in Other current assets and "Regulatory liabilities, current," which was previously included in Accrued liabilities. The Statement of Cash Flows for December 31, 2008 and 2007 has been modified within Net cash provided by operating activities to reflect "Regulatory assets," which was previously included in Other operating activities and "Regulatory liabilities," which was previously included in Other operating activities. The Statement of Cash Flows for December 31, 2008 and 2007 has been modified within Net cash provided by operating activities to reflect "Other non-cash" which was previously included in Other operating activities.

Use of Estimates

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. The most significant estimates relate to allowance for uncollectible accounts receivable, unbilled revenues, long-lived asset values and useful lives, asset retirement obligations, employee benefits plans and contingency accruals. Actual results could differ from those estimates.

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 ratemaking 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 generation 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.

As of December 31, 2009 and 2008, we had \$22.6 million and \$24.6 million, respectively, in net regulatory assets for which we recover the costs, but we do not earn a return.

On December 31, 2009 and 2008, we had the following regulatory assets and liabilities (in thousands):

	Recovery Period	2009	2008
Regulatory assets:			
Unamortized loss on reacquired debt	14 years	$ 2,207	$ 2,367
AFUDC	Up to 45 years	7,579	4,995
Defined benefit postretirement plans	Up to 17 years	21,024	26,256
Deferred energy costs	Less than one year	7,467	4,382
Other		495	200
Total regulatory assets		$ 38,772	$ 38,200
Regulatory liabilities:			
Cost of removal for utility plant	Up to 53 years	$ 13,678	$ 11,705
Other		2,515	1,936
Total regulatory liabilities		$ 16,193	$ 13,641

Regulatory assets are primarily recorded for the probable future revenue to recover the costs associated with defined benefit postretirement plans, future income taxes related to the deferred tax liability for the equity component of AFUDC of utility assets and unamortized losses on reacquired debt. To the extent that energy costs are under-recovered or over-recovered during the year, they are recorded as a regulatory asset or liability, respectively. Regulatory liabilities include the probable future decrease in rate revenues related to a decrease in deferred tax liabilities for prior reductions in statutory federal income tax rates, gains associated with regulated utilities' defined benefit postretirement plans and the cost of removal for utility plant, recovered through our electric utility rates. Regulatory assets are included in Regulatory assets, current and Regulatory assets, non-current on the accompanying Balance Sheet. Regulatory liabilities are included in Regulatory liabilities, current and Regulatory liabilities, non-current on the accompanying Balance Sheet.

Allowance for Funds Used During Construction

AFUDC represents the approximate composite cost of borrowed funds and a return on capital used to finance a project. AFUDC for the years ended December 31, 2009, 2008 and 2007 was $10.2 million, $6.2 million and $0.9 million, respectively. The equity component of AFUDC for 2009, 2008 and 2007 was $5.8 million, $3.6 million and $0.6 million, respectively. The borrowed funds component of AFUDC for 2009, 2008 and 2007 was $4.4 million, $2.6 million and $0.3 million, respectively. The equity component of AFUDC is included in Other income, and the borrowed funds component of AFUDC is netted in Interest expense on the accompanying Statements of Income.

Cash Equivalents

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

Allowance for Doubtful Accounts

We maintain an allowance for doubtful accounts which reflects our best estimate of potentially uncollectible trade receivables. We regularly review our trade receivables allowances by considering such factors as historical experience, credit-worthiness, the age of the receivable balances and current economic conditions that may affect the ability to pay.

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

	2009	2008
Accounts receivable trade	$ 14,703	$ 18,860
Unbilled revenues	5,547	5,391
Total accounts receivable – customers	20,250	24,251
Allowance for doubtful accounts	(259)	(370)
Net accounts receivable	$ 19,991	$ 23,881

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are generally stated on a weighted-average cost basis. To the extent fuel has been designated as the underlying hedged item in a "fair value" hedge transaction, those volumes are stated at market value using published industry quotations. As of December 31, 2009 and 2008, there were no market adjustments related to fuel.

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. 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 are charged to operations as incurred.

Depreciation provisions for regulated electric property, plant and equipment is computed on a straight-line basis using an annual composite rate of 2.8% in 2009, 3.2% in 2008 and 3.1% in 2007. Based on a rate study, the new composite rate of 2.8% went into effect August 2009.

Derivatives and Hedging Activities

From time to time we utilize risk management contracts including forward purchases and sales and fixed-for-float swaps to hedge the price of fuel for our combustion turbines, maximize the value of our natural gas storage or fix the interest on our 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 allows 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, net of tax, and be reclassified into earnings 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.

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. No impairment loss was recorded during 2009, 2008 or 2007.

Income Taxes

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

We file a federal income tax return with other affiliates. For financial statement purposes, federal income taxes are allocated to the individual companies based on amounts calculated on a separate return basis.

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.

Recently Adopted Accounting Standards

FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles, ASC 105

On July 1, 2009, the FASB Accounting Standards Codification™ became the source of authoritative GAAP recognized by the FASB to be applied by non-governmental entities. On the effective date of this Statement, the Codification superseded all then-existing non-SEC accounting and reporting standards. All other non-SEC accounting literature not included or grandfathered in the Codification became non-authoritative. This Statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009.

Following this Statement, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Task Force Abstracts. Instead, it will issue Accounting Standards Updates. The FASB will not consider Accounting Standards Updates as authoritative in their own right. Accounting Standards Updates will serve only to update the Codification, provide background information about the guidance, and provide the basis for conclusions on the change(s) in the Codification.

Business Combinations, ASC 805

The ASC for Business Combinations requires that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. It also establishes principles and requirements for how the acquirer (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree, (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase and (iii) discloses the nature and financial effects of the business combination; and requires restructuring and acquisition-related costs to be expensed. In addition, if income tax liabilities are settled for an amount other than as previously recorded, such adjustments could affect income tax expense in the period of adjustment. Effective January 1, 2009, any impact the standard will have on our consolidated financial statements will depend on the nature and magnitude of any future acquisitions we consummate including any tax-related adjustments.

Derivative and Hedging, ASC 815

The ASC for Derivative and Hedging Disclosures includes requirements for enhanced disclosures about derivative and hedging activities and their affect on an entity's financial position, financial performance and cash flows. Accounting standards for derivatives and hedging encourages, but does not require, disclosures for earlier periods presented for comparative purposes at initial adoption. Required disclosures for periods subsequent to January 1, 2009 are provided in Note 4.

Fair Value Measurements and Disclosures, ASC 820

The ASC for Fair Value Measurements and Disclosures defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. This does not expand the application of fair value accounting to any new circumstances, but applies the framework to other applicable GAAP that requires or permits fair value measurement. We apply fair value measurements to certain assets and liabilities, primarily commodity derivatives.

Financial Instruments, ASC 825
The ASC for Financial Instruments requires public companies to provide more frequent disclosures about the fair value of their financial instruments for interim and annual periods ending after June 15, 2009. These disclosures are included in Note 6.

Subsequent Events, ASC 855

The ASC for Subsequent Events establishes general standards of accounting for and disclosures of events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. These standards and disclosures were applied to our financial statements issued after June 15, 2009.

Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, ASC 715

The ASC for Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of financial position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position and provides for related disclosures. Effective for fiscal years ending after December 15, 2008, this accounting standard required the measurement of the funded status of the plan to coincide with the date of the year-end statement of financial position. Therefore, the measurement date for the funded status of our pension and other postretirement benefit plans was changed to December 31 from September 30. ASC 715 also provides guidance on an employer's disclosure about plan assets for a defined benefit pension or other postretirement plans. These disclosures are effective for fiscal years ending after December 15, 2009. See Note 9 for additional information.

Recently Issued Accounting Standards

Consolidation of Variable Interest Entities, ASC 810-10-15

In June 2009, the FASB issued a revision regarding consolidations. The revised accounting guidance requires a company to consider whether an entity that is insufficiently capitalized or is not controlled through voting should be consolidated. It will require additional disclosures about the involvement with variable interest entities and any significant changes in risk exposure due to that involvement. This standard is effective for annual periods that begin after November 15, 2009. We are currently assessing the impact that the adoption of this standard will have on our financial condition, results of operations, and cash flows.

Fair Value Measurements, ASC 820

In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3, fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods and were effective for the Company on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. The guidance will require additional disclosures, but will not impact our financial position or results of operations.

(2) PROPERTY, PLANT AND EQUIPMENT

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

	2009	2009 Weighted Average Useful Life	2008	2008 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 336,534	53	$ 326,606	47	30-62
Transmission	86,841	44	70,470	45	35-55
Distribution	264,847	37	249,652	37	15-65
Plant acquisition adjustment	4,870	32	4,870	32	32
General	55,701	22	47,127	23	10-50
Total electric plant	748,793		698,725		
Less accumulated depreciation and amortization	293,823		281,220		
Electric plant net of accumulated depreciation and amortization	454,970		417,505		
Construction work in progress	201,784		144,966		
Net electric plant	$ 656,754		$ 562,471		

(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 and PacifiCorp owns an 80% interest in the Wyodak Plant (Plant), a 362 MW coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp is the operator of the Plant. We receive 20% of the Plant's capacity and are committed to pay 20% of its additions, replacements and operating and maintenance expenses. As of December 31, 2009 and 2008, our investment in the Plant included $79.8 million and $79.1 million, respectively, in electric plant and $52.2 million and $50.8 million, respectively, in accumulated depreciation, and is included in the corresponding captions in the accompanying Balance Sheets. Our share of direct expenses of the Plant was $8.0 million, $8.0 million and $7.3 million for the years ended December 31, 2009, 2008 and 2007, respectively, and is included in the corresponding categories of operating expenses in the accompanying Statements of Income.

- We also own a 35% interest and Basin Electric owns a 65% interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. 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 35% of the additions, replacements and operating and maintenance expenses. Our share of direct expenses was $0.1 million for each of the years ended December 31, 2009, 2008 and 2007. As of December 31, 2009 and 2008, our investment in the transmission tie was $19.6 million and $19.8 million, with $3.8 million and $2.5 million, respectively, of accumulated depreciation and is included in the corresponding captions in the accompanying Balance Sheets.

- The Balance Sheet includes our ownership interest in the assets and liabilities of the Wygen III facility currently under construction. We own 75% of Wygen III and MDU owns 25%. Wygen III is expected to commence operations by April 1, 2010. Included in the December 31, 2009 Balance Sheet in Construction Work in Progress was $175.6 million. During 2009, we were reimbursed $48.4 million for the construction. Our share of direct expenses of the jointly-owned facility is included in Operating expenses in the Statements of Income.

(4) RISK MANAGEMENT

We hold natural gas in storage for use as fuel for generating electricity with our gas-fired combustion turbines. To minimize associated price risk and seasonal storage level requirements, we utilize various derivative instruments in managing these risks. As of December 31, 2008, there were no derivative contracts outstanding. As of December 31, 2009, we had the following derivatives and related balances included in Accrued liabilities on the accompanying Balance Sheet (dollars, in thousands):

		Natural Gas Swaps
Notional*		232,500
Maximum terms in months		10
Current derivative liabilities	$	5
Pre-tax accumulated other comprehensive loss	$	(5)

* Gas in MMbtus.

(5) LONG-TERM DEBT

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

		2009		2008
First mortgage bonds:				
8.06% due 2010	$	30,000	$	30,000
9.49% due 2018		2,520		2,810
9.35% due 2021		19,980		21,645
7.23% due 2032		75,000		75,000
6.125% due 2039		180,000		-
Unamortized discount on 6.125% bonds		(124)		-
		307,376		129,455
Other long-term debt:				
Pollution control revenue bonds at 4.8% due 2014		6,450		6,450
Pollution control revenue bonds at 5.35% due 2024		12,200		12,200
Other		3,043		3,104
		21,693		21,754
Total long-term debt		329,069		151,209
Less current maturities		(32,025)		(2,016)
Net long-term debt	$	297,044	$	149,193

On October 27, 2009, we completed a $180 million first mortgage bond issuance. The bonds were priced at 99.931% of par and a reoffer yield of 6.13%. The bonds mature November 1, 2039 and carry an annual interest rate of 6.125%, which is scheduled to be paid semi-annually. We received proceeds net of underwriting fees of $178.3 million which were used to repay intercompany borrowings from BHC, primarily incurred to fund the construction of Wygen III. Deferred finance costs of approximately $2.2 million were capitalized and will be amortized over the term of the bonds.

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.

Scheduled maturities are approximately $32.0 million in 2010; $2.0 million a year for the years 2011, 2012 and 2013; $8.4 million in 2014; and $282.7 million thereafter.

(6) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 1,709	$ 1,709	$ 4	$ 4
Derivative financial instruments – accrued liabilities	$ 5	$ 5	$ -	$ -
Long-term debt, including current maturities	$ 329,069	$ 344,942	$ 151,209	$ 144,107

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

Cash and Cash Equivalents

The carrying amount approximates fair value due to the short maturity of these instruments.

Derivative Financial Instruments

These instruments are carried at fair value. Descriptions of the instruments we use are included in Note 4.

Long-Term Debt

The fair value of our long-term debt is estimated based on quoted market rates for debt instruments having similar maturities and similar debt ratings. Our outstanding first mortgage bonds are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefits for us to call and refinance the first mortgage bonds.

(7) INCOME TAXES

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

	2009	2008	2007
Current	$ (3,296)	$ (6,521)	$ 8,704
Deferred	11,600	16,072	3,864
Total income tax expense	$ 8,304	$ 9,551	$ 12,568

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

Years ended December 31,	2009	2008
Deferred tax assets, current:		
Asset valuation reserve	$ 90	$ 129
Employee benefits	946	932
Other	2	-
Total deferred tax assets, current	1,038	1,061
Deferred tax liabilities, current:		
Prepaid expenses	214	213
Deferred costs	2,677	1,580
Total deferred tax liabilities, current	2,891	1,793
Net deferred tax liability, current	$ 1,853	$ 732
Deferred tax assets, non-current:		
Plant related differences	$ 1,151	$ 1,151
Regulatory liabilities	7,847	10,156
Employee benefits	3,468	3,528
Items of other comprehensive income	175	227
Research and development credit	1,038	-
Other	128	128
Total deferred tax assets, non-current	13,807	15,190
Deferred tax liabilities, non-current:		
Accelerated depreciation and other plant related differences	93,253	83,112
AFUDC	4,926	3,247
Regulatory assets	10,011	11,270
Employee benefits	1,052	2,237
Other	772	828
Total deferred tax liabilities, non-current	110,014	100,694
Net deferred tax liability, non-current	$ 96,207	$ 85,504
Net deferred tax liability	$ 98,060	$ 86,236

The following table reconciles the change in the net deferred income tax liability from December 31, 2008, to December 31, 2009, to the deferred income tax expense (in thousands):

	2009	2008
Increase in deferred income tax liability from the preceding table	$ 11,824	$ 16,457
Deferred taxes related to regulatory assets and liabilities	(1,323)	(1,200)
Deferred taxes associated with other comprehensive income	(73)	38
Deferred taxes related to property basis differences	2,851	767
Deferred taxes related to AFUDC	(1,679)	-
Other	-	10
Deferred income tax expense for the period	$ 11,600	$ 16,072

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

	2009	2008	2007
Federal statutory rate	35.0%	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.9)	(0.7)	(1.0)
Equity AFUDC	(6.2)	(3.6)	-
Other	(1.5)	(1.1)	(0.5)
	26.4%	29.6%	33.5%

We adopted the accounting standards for uncertain tax positions on January 1, 2007 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with accounting standards for income taxes. The accounting standards prescribe a recognition threshold and measurement attributes for the financial statement recognition and measurement of a tax position taken or expected to be taken. The impact of this implementation had no effect on our financial statements.

The following table reconciles the total amounts of unrecognized tax benefits at the beginning and end of the period (in thousands):

	2009	2008
Unrecognized tax benefits at January 1	$ 767	$ -
Additions for prior year tax positions	3,110	-
Additions for current year tax positions	-	767
Unrecognized tax benefits at December 31	$ 3,877	$ 767

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.3 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the year ended December 31, 2009, the interest expense recognized was not material to our financial results.

We file income tax returns in the United States federal jurisdiction. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statutes of limitations prior to December 31, 2010.

(8) COMPREHENSIVE INCOME

The following tables display each component of Other Comprehensive Income (Loss) and the related tax effects for the years ended December 31, (in thousands):

2009

	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Pension liability adjustment	$ 150	$ (52)	$ 98
Reclassification adjustments of cash flow hedges settled and included in net income	64	(24)	40
Net change in fair value of derivatives designated as cash flow hedges	(5)	3	(2)
Other comprehensive income	$ 209	$ (73)	$ 136

2008

	Pre-tax Amount	Tax Benefit	Net-of-tax Amount
Pension liability adjustment	$ (4)	$ 1	$ (3)
Reclassification adjustments of cash flow hedges settled and included in net income	(107)	38	(69)
Other comprehensive loss	$ (111)	$ 39	$ (72)

2007

	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Pension liability adjustment	$ 115	$ (39)	$ 76
Reclassification adjustments of cash flow hedges settled and included in net income	424	(148)	276
Net change in fair value of derivatives designated as cash flow hedges	(1,069)	372	(697)
Other comprehensive loss	$ (530)	$ 185	$ (345)

Balances by classification included within Accumulated other comprehensive loss on the accompanying Balance Sheets at December 31 are as follows (in thousands):

	2009	2008
Derivatives designated as cash flow hedges	$ (893)	$ (932)
Employee benefit plans	(320)	(417)
Total accumulated other comprehensive loss	$ (1,213)	$ (1,349)

(9) EMPLOYEE BENEFIT PLANS

Funded Status of Benefit Plans

The funded status of postretirement benefit plans is required to be recognized in the statement of financial position. The funded status for pension plans 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.

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.

The measurement date of plans should be the date of our year-end balance sheet. We had used a September 30 measurement date. During 2008, we changed the measurement date to December 31. Therefore, $0.2 million, net of tax, was recognized as an adjustment to retained earnings.

Defined Benefit Pension Plan

We have a noncontributory defined benefit pension plan (Plan) covering the employees who meet certain eligibility requirements. The benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. Our funding policy is in accordance with the federal government's funding requirements. The Plan's assets are held in trust and consist primarily of equity and fixed income investments. We use a December 31 measurement date for the Plan.

In July 2009, the Board of Directors approved a freeze to our Defined Benefit Pension Plan (with the exception of bargaining unit participants). The freeze is effective January 1, 2010 and eliminates new non-bargaining unit employees from participation in the plan, and freezes the benefits of current non-bargaining unit participants except for the following group: those non-bargaining participants who are both 1) are age 45 or older as of December 31, 2009 and have 10 years or more of credited service as of January 1, 2010; and 2) elect to continue to accrue additional benefits under the pension plan and consequently forego the additional age- and points-based employer contribution under our 401(k) retirement savings plan. Plan assets and obligations were revalued July 31, 2009 in conjunction with the freeze, and we recognized a pre-tax curtailment expense of approximately $0.2 million in the third quarter of 2009.

The Plan's expected long-term rate of return on assets assumption is based upon the weighted average expected long-term rate of returns for each individual asset class. The asset class weighting is determined using the target allocation for each asset class in the Plan portfolio. The expected long-term rate of return for each asset class is determined primarily from adjusted long-term historical returns for the asset class. It is anticipated that long-term future returns will not achieve historical results.

The expected long-term rate of return for equity investments was 9.5% for the 2009 and 2008 plan years. For determining the expected long-term rate of return for equity assets, we reviewed interest rate trends and annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2009, 8.1%, 11.1%, 9.7% and 9.3%, respectively. Fund management fees were estimated to be 0.18% for S&P 500 Index assets and 0.45% for other assets. The expected long-term rate of return on fixed income investments was 6.0%; the return was based upon historical returns on 10-year treasury bonds of 6.9% from 1962 to 2009, and adjusted for recent declines in interest rates. The expected long-term rate of return on cash investments was estimated to be 1.0%, which was based upon current one-year LIBOR rates.

Plan Assets

Percentage of fair value of Plan assets at December 31:

	2009	2008
Equity	72%	68%
Fixed income	25	28
Cash	3	4
Total	100%	100%

The Investment Policy for the Pension Plans is to seek to achieve the following long-term objectives: 1) a rate of return in excess of the annualized inflation rate based on a five-year moving average; 2) a rate of return that meets or exceeds the assumed actuarial rate of return that meets or exceeds the assumed actuarial rate of return as stated in the Plan's actuarial report; 3) a rate of return on investments, net of expenses, that is equal to or exceeds various benchmark rates on a moving three-year average, and 4) maintenance of sufficient income and liquidity to pay monthly retirement benefits. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity and fixed income assets.

The policy contains certain prohibitions on transactions in separately managed portfolios in which the Plan may invest, including prohibitions on short sales.

Cash Flows

We made no contributions to the Plan in 2009 and expect no contributions to the Plan in 2010.

Supplemental Non-qualified Defined Benefit Retirement Plans

We have various supplemental retirement plans for key executives. The Plans are non-qualified defined benefit plans. We use a December 31 measurement date for the Plans. Effective January 1, 2010, we eliminated a non-qualified pension plan in which some of our officers participated due to the partial freeze of our qualified pension plans. We also amended the NQDC, which was adopted in 1999. The NQDC is a non-qualified deferred compensation plan that provides executives with an opportunity to elect to defer compensation and receive benefits without reference to the limitations on contributions in the Plan or those imposed by the IRS. The amended NQDC provides for non-elective non-qualified restoration benefits to certain officers who are not eligible to continue accruing benefits under the Defined Benefit Pension Plans and associated non-qualified pension restoration plans. All contributions to the non-qualified plans are subject to a graded vesting schedule of 20% per year over five years with vesting credit beginning with service in the Plan on and after January 1, 2010.

Plan Assets

The Plan has no assets. We fund on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contribution is expected to be $0.1 million in 2010. Contributions are expected to be made in the form of benefit payments.

Non-pension Defined Benefit Postretirement Plan

Employees who are participants in our Postretirement Healthcare Plan and who retire on or after attaining age 55 after completing at least five years of service 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 Plan periodically. We are not pre-funding our retiree medical plan. We use a December 31 measurement date for the Plan. In July 2009, the Board of Directors approved a freeze to the Plan which changed the structure of the Plan for non-union employees to a Retiree Medical Savings Account structure and expanded eligibility of Plan participants, effective January 1, 2010.

It has been determined that the Plan's post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy. The effect of the Medicare Part D subsidy on the accumulated postretirement benefit obligation for the fiscal year ending December 31, 2009, was an actuarial gain of approximately $0.9 million. The effect on 2009 net periodic postretirement benefit cost was a decrease of approximately $0.1 million.

Plan Assets

The Plan has no assets. We fund on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contributions are expected to be $0.4 million in 2010. Contributions are expected to be made in the form of benefit payments.

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). The pension plan is able to classify fair value balances based on the observability of inputs.

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.

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, 2009 and 2008 (in thousands):

Defined Benefit Pension Plan	At Fair Value as of December 31, 2009			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Registered Investment Companies	$ 22,632	$ -	$ -	$ 22,632
Common Collective Trust	-	16,408	-	16,408
Total investments measured at fair value	$ 22,632	$ 16,408	$ -	$ 39,040

Defined Benefit Pension Plan	At Fair Value as of December 31, 2008			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Registered Investment Companies	$ 17,976	$ -	$ -	$ 17,976
Common Collective Trust	-	14,124	-	14,124
Total investments measured at fair value	$ 17,976	$ 14,124	$ -	$ 32,100

Plan Reconciliations

The following tables provide a reconciliation of the Employee Benefit Plan's obligations and fair value of assets for 2009 and 2008, components of the net periodic expense for the years ended 2009, 2008 and 2007 and elements of regulatory assets and liabilities and AOCI for 2009 and 2008 (in thousands):

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 51,965	$ 48,937	$ 1,672	$ 1,958	$ 7,393	$ 6,649
Service cost	1,155	1,396	-	-	216	264
Interest cost	3,143	3,790	100	150	444	522
Actuarial loss	1,686	2,712	7	65	3,474	506
Amendments	100	-	-	-	(1,960)	-
Discount rate change	1,047	-	-	-	-	-
Benefits paid	(2,312)	(2,838)	(89)	(142)	(579)	(830)
Asset transfer to affiliate	(121)	(2,032)	-	(359)	(23)	(297)
Plan curtailment reduction	(1,048)	-	-	-	-	-
Medicare Part D adjustment	-	-	-	-	46	71
Plan participant's contributions	-	-	-	-	421	508
Net increase (decrease)	3,650	3,028	18	(286)	2,039	744
Projected benefit obligation at end of year	$ 55,615	$ 51,965	$ 1,690	$ 1,672	$ 9,432	$ 7,393

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

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Beginning market value of plan assets	$ 32,100	$ 52,466	$ -	$ -	$ -	$ -
Investment income (loss)	9,337	(8,771)	-	-	-	-
Benefits paid	(2,312)	(2,249)	-	-	-	-
Asset transfer to affiliate	(85)	-	-	-	-	-
Ending market value of plan assets	$ 39,040	$ 41,446	$ -	$ -	$ -	$ -

Amounts recognized in the statement of financial position consist of (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Regulatory asset (liability)	$ 19,580	$ 26,256	$ -	$ -	$ 1,443	$ (11)
Current liability	$ -	$ -	$ 98	$ 109	$ 325	$ 223
Non-current liability	$ (16,576)	$ (19,864)	$ (1,592)	$ (1,564)	$ (9,110)	$ (7,169)

Accumulated Benefit Obligation

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Accumulated benefit obligation	$ 47,745	$ 43,894	$ 1,645	$ 1,622	$ 9,432	$ 7,393

Components of Net Periodic Expense

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2009	2008	2007	2009	2008	2007	2009	2008	2007
Service cost	$ 1,155	$ 1,117	$ 1,137	$ -	$ -	$ -	$ 216	$ 211	$ 211
Interest cost	3,143	3,032	2,923	100	120	116	444	417	398
Expected return on assets	(2,780)	(4,374)	(3,885)	-	-	-	-	-	-
Amortization of prior service cost	87	112	103	-	1	1	-	-	-
Amortization of transition obligation	-	-	-	-	-	-	51	51	51
Recognized net actuarial loss (gain)	1,586	-	408	43	44	57	-	(1)	-
Curtailment expense	189	-	-	-	-	-	-	-	-
Net periodic expense	$ 3,380	$ (113)	$ 686	$ 143	$ 165	$ 174	$ 711	$ 678	$ 660

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, are as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Net loss	$ -	$ -	$ (324)	$ (347)	$ -	$ -
Prior service cost	-	-	-	(1)	-	-
Transition obligation	-	-	-	-	-	-
	$ -	$ -	$ (324)	$ (348)	$ -	$ -

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 2010 are as follows (in thousands):

	Defined Benefits Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
Net loss	$ 895	$ 20	$ 111
Prior service cost	41	-	(91)
Transition obligation	-	-	-
Total net periodic benefit cost expected to be recognized during calendar year 2010	$ 936	$ 20	$ 20

Assumptions

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
Weighted-average assumptions used to determine benefit obligations:	2009	2008	2007	2009	2008	2007	2009	2008	2007
Discount rate	6.05%	6.20%	6.35%	6.10%	6.20%	6.35%	5.90%	6.10%	6.35%
Rate of increase in compensation levels	4.25%	4.25%	4.34%	5.00%	5.00%	5.00%	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2009	2008	2007	2009	2008	2007	2009	2008	2007
Discount rate	6.25%	6.35%	5.95%	6.20%	6.35%	5.95%	6.10%	6.35%	5.95%
Expected long-term rate of return on assets*	8.50%	8.50%	8.50%	N/A	N/A	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	4.25%	4.34%	4.31%	5.00%	N/A	5.00%	N/A	N/A	N/A

* The expected rate of return on plan assets changed to 8.00% for the calculation of the 2010 net periodic pension cost.

The healthcare cost trend rate assumption for 2009 fiscal year benefit obligation determination and 2010 fiscal year expense is a 10% increase for 2009 grading down until a 4.5% ultimate trend rate is reached in fiscal year 2027. The healthcare cost trend rate assumption for the 2008 fiscal year benefit obligation determination and 2009 fiscal year expense was a 9% increase for 2009 grading down 1% per year until a 5% ultimate trend rate is reached in fiscal year 2013.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1% increase in the healthcare cost trend assumption would increase the service and interest cost $0.1 million or 22% and the accumulated periodic postretirement benefit obligation $1.3 million or 14%. A 1% decrease would reduce the service and interest cost by $0.1 million or 17% and the accumulated periodic postretirement benefit obligation $1.0 million or 11%.

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

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plan	Non-pension Defined Benefit Postretirement Plans: Expected Gross Benefit Payments	Expected Medicare Part D Drug Benefit Subsidy	Expected Net Benefit Payments
2010	$ 2,584	$ 98	$ 405	$ (80)	$ 325
2011	2,743	112	486	(86)	400
2012	2,833	94	544	(94)	450
2013	2,975	77	585	(101)	484
2014	3,152	93	628	(107)	521
2015-2019	18,086	557	3,683	(624)	3,059

Defined Contribution Plan

The Parent sponsors a 401(k) retirement savings plan in which employees may participate. Participants may elect to invest up to 50% of their eligible compensation on a pre-tax basis, up to a maximum amount established by the Internal Revenue Service. We provide a matching contribution of 100% of the employee's annual contribution up to a maximum of 3% of eligible compensation. Matching contributions vest at 20% per year and are fully vested when the participant has 5 years of service. Our matching contributions were \$0.7 million for 2009, \$0.7 million for 2008 and \$0.6 million for 2007.

Effective January 1, 2010 in conjunction with the partial freeze of our defined benefit pension plan, we amended our 401(k) Retirement Savings Plan. This freeze covers all employees with the exception of the bargaining unit employees and certain other employees grandfathered under a prior defined benefit plan election. The amendment provides for a matching contribution of 100% of the eligible employee's annual contribution up to a maximum of 6% of eligible compensation. The amendment also provides certain eligible participants an age and service-based employer contribution.

(10) RELATED-PARTY TRANSACTIONS

Receivables and Payables

We have accounts receivable balances related to transactions with other BHC subsidiaries. The balances were \$4.1 million and \$12.6 million as of December 31, 2009 and 2008, respectively. We also have accounts payable balances related to transactions with other BHC subsidiaries. The balances were \$10.0 million and \$10.4 million as of December 31, 2009 and 2008, respectively.

Money Pool Notes Receivable and Notes Payable

We have a Utility Money Pool Agreement with the Parent, Cheyenne Light and Black Hills Utility Holdings. Under the agreement, we may borrow from the Parent. The Agreement restricts us from loaning funds to the Parent or to any of the Parent's non-utility subsidiaries; the Agreement does not restrict us from making dividends to the Parent. Borrowings under the agreement bear interest at the daily cost of external funds 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 100 basis points.

Through the Utility Money Pool, we have a net note receivable balance to the Parent of \$57.7 million as of December 31, 2009 and a net note payable balance of \$70.2 million as of December 31, 2008. Advances under this note bear interest at 0.70% above the daily LIBOR rate (0.93% at December 31, 2009). Net interest expense of \$1.1 million and \$0.9 million was recorded for the years ended December 31, 2009 and 2008, respectively. During 2007, we had a note receivable of \$10.3 million for which we received \$0.9 million of interest income.

Other Balances and Transactions

We received revenues of approximately $0.9 million, $1.2 million and $1.9 million for the years ended December 31, 2009, 2008 and 2007, respectively, from Black Hills Wyoming, Inc. for the transmission of electricity.

We received revenues of approximately $1.8 million and $2.8 million for the years ended December 31, 2009 and 2008, respectively, from Cheyenne Light for the sale of electricity and dispatch services.

We recorded revenues of $0.2 million and $1.4 million for the years ending December 31, 2008 and 2007, respectively, relating to payments received pursuant to a natural gas swap entered into with Enserco.

We purchase coal from WRDC. The amount purchased during the years ended December 31, 2009, 2008 and 2007 was $16.3 million, $15.5 million and $12.6 million, respectively. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.

We purchase excess power generated by Cheyenne Light. The amount purchased during the years ended December 31, 2009 and 2008 was $8.6 million and $6.4 million, respectively.

In order to fuel our combustion turbine, we purchase natural gas from Enserco. The amount purchased during the years ended December 31, 2009, 2008 and 2007 was approximately $2.3 million, $8.0 million and $4.5 million, respectively. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.

In addition, we also pay the Parent for allocated corporate support service cost incurred on our behalf. Corporate costs allocated from the Parent were $15.0 million, $12.4 million and $11.3 million for the years ended December 31, 2009, 2008 and 2007, respectively.

We have funds on deposit from Black Hills Wyoming for transmission system reserve in the amount of $2.0 million and $1.9 million at December 31, 2009 and 2008, respectively, which is included in Deferred credits and other liabilities, Other on the accompanying Balance Sheets. Interest on the deposit accrues quarterly at an average prime rate (3.25% at December 31, 2009). We paid interest expense of $0.1 million for each of the years ended December 31, 2009, 2008 and 2007, respectively.

We have two contracts with Cheyenne Light under which Cheyenne Light sells up to 40 MW of wind-generated, renewable energy to us. Purchases from these agreements during 2009 were $2.8 million and $0.6 million in 2008.

(11) SUPPLEMENTAL CASH FLOWS INFORMATION

Years ended December 31,	2009	2008 (in thousands)	2007
Non-cash investing and financing activities -			
Property, plant and equipment financed with accrued liabilities	$ 10,191	$ 13,294	$ 1,323
Distribution to Parent	$ 225,000	$ -	$ -
Borrowing from Parent	$ 200,000	$ -	$ -
Supplemental disclosure of cash flow information:			
Cash paid during the period for -			
Interest (net of amounts capitalized)	$ 14,252	$ 11,578	$ 11,782
Income taxes (refunded) paid	$ (3,700)	$ (5,877)	$ 17,284

(12) COMMITMENTS AND CONTINGENCIES

Partial Sale of Wygen III to MDU

On April 9, 2009, we sold to MDU a 25% ownership interest in our Wygen III generation facility currently under construction. At closing, MDU made a payment to us for its 25% share of the costs to date on the ongoing construction of the facility. Proceeds of $32.8 million were received of which $30.2 million was used to pay down a portion of the Acquisition Facility. MDU will continue to reimburse us for its 25% of the total costs paid to complete the project. In conjunction with the sales transaction, we also modified a 2004 PPA between us and MDU.

Power Purchase and Transmission Services Agreements

We have the following purchase power and transmission agreements as of December 31, 2009:

- A PPA with PacifiCorp expiring in 2023, which provides for the purchase by us of 50 MW of electric capacity and energy. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants. Costs incurred under this agreement were $11.8 million in 2009, $11.6 million in 2008 and $10.9 million in 2007.

- 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 2023. Costs incurred under this agreement were $1.2 million in each of the years ended 2009, 2008 and 2007, respectively.

- Cheyenne Light entered into a 20-year PPA with Happy Jack for 29.4 MW of energy. Under a separate inter-company agreement, Cheyenne Light has agreed to sell 20 MW of energy from Happy Jack to us;

- Cheyenne Light entered into a 20-year PPA with Silver Sage for 30 MW of energy. Commercial operations commenced on October 1, 2009. Under a separate inter-company agreement, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to us; and

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

Long-Term Power Sales Agreements

We have the following power sales agreements as of December 31, 2009:

- A contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 MW of capacity and energy. The agreement renews automatically and requires a seven-year notice of termination. This contract is integrated into our control area and is treated as part of our firm native load. As of December 31, 2009, neither party to the agreement had given notice of termination;

- An agreement under which we supply up to 74 MW of capacity and energy to MDU for the Sheridan, Wyoming electric service territory through the end of 2016. The sales to MDU have been integrated into our control area and are considered part of our firm native load. In accordance with the terms of the agreement, MDU exercised its option to participate in the ownership of the Wygen III plant that is currently being constructed. Under an agreement entered into in April 2009, MDU purchased a 25% undivided interest in the Wygen III plant. We retain responsibility for operations of the facility with a life-of-plant lease and agreements with MDU for operations and coal supply. In conjunction with the sales transaction, we also modified the 2004 PPA under which we supplied MDU with 74 MW of capacity and energy through 2016. The PPA with MDU will be supplied from its ownership interest in Wygen III. During periods of reduced production at Wygen III, or during periods when Wygen III is offline, we will provide MDU with its first 25 MW from our other generation facilities or from system purchases; and

- An agreement under which we supply 20 MW of energy and capacity to MEAN under a contract that expires in 2023. This contract is unit-contingent based on the availability of our Neil Simpson II and Wygen III plants, with capacity purchase decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

  2010-2017 20 MW - 10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
  2018-2019 15 MW - 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
  2020-2021 12 MW - 6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
  2022-2023 10 MW - 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II; and

- A five-year PPA with MEAN which commences the month following the onset of commercial operations of Wygen III. Under this contract, MEAN will purchase 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

Legal Proceedings

Ongoing Litigation

We are subject to various legal proceedings, claims and litigation which arise in the ordinary course of operations. In the opinion of management, the amount of liability, if any, with respect to these actions would not materially affect our financial position, results of operations or cash flows.

(13) 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 of 2009 and 2008 (in thousands):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2009:				
Operating revenues	$ 54,458	$ 46,836	$ 53,086	$ 52,699
Operating income	10,705	5,006	8,920	10,174
Net income	6,964	3,105	7,166	5,904
2008:				
Operating revenues	$ 57,632	$ 57,978	$ 59,358	$ 57,706
Operating income	10,591	9,270	10,228	8,547
Net income	5,576	5,251	6,371	5,561

(14) SUBSEQUENT EVENT

In February 2010, we provided notice to the bondholders of our intent to call the BHP Series Y bonds in full. These bonds were originally due in 2018. The balance of $2.5 million plus an early redemption premium of 2.6% will be paid on March 31, 2010.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2009

	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: 2009

	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	5,970	5,970	
36	362	Station Equipment	445,583	445,583	
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	388,761	388,761	0%
39	365	Overhead Conductors & Devices	415,751	427,905	-3%
40	366	Underground Conduit	909	909	
41	367	Underground Conductors & Devices	15,834	15,834	
42	368	Line Transformers	44,307	46,941	-6%
43	369	Services	3,367	3,367	0%
44	370	Meters	15,981	13,258	21%
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49		**TOTAL Distribution Plant**	1,362,767	1,374,831	-1%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2009

	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	14,732	14,732	
13	398	Miscellaneous Equipment			
14	399	Other Tangible Property			
15					
16	**TOTAL General Plant**		14,732	14,732	
17					
18	**TOTAL Electric Plant in Service**		1,377,498	1,389,563	-1%

MONTANA DEPRECIATION SUMMARY

Year: 2009

	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	1,374,831	220,280	912,201	
8	General	14,732	10,031	10,597	
9	**TOTAL**	1,389,563	230,311	922,798	

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		45.81%		
13	Preferred Stock				
14	Long Term Debt		54.19%		
15	Other				
16	**TOTAL**		100.00%		

STATEMENT OF CASH FLOWS

Year: 2009

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	22,759,259	23,138,854	-2%
6	Depreciation	20,778,346	19,313,360	8%
7	Amortization	448,376	461,368	-3%
8	Deferred Income Taxes - Net	16,141,109	11,724,815	38%
9	Investment Tax Credit Adjustments - Net	(69,171)	(124,398)	44%
10	Change in Operating Receivables - Net	(5,298,011)	13,301,001	-140%
11	Change in Materials, Supplies & Inventories - Net	(3,681,392)	484,106	-860%
12	Change in Operating Payables & Accrued Liabilities - Net	9,742,252	(13,776,381)	171%
13	Allowance for Funds Used During Construction (AFUDC)	(3,604,543)	(5,831,355)	38%
14	Change in Other Assets & Liabilities - Net	(11,122,920)	(10,072,860)	-10%
15	Other Operating Activities (explained on attached page)			
16	**Net Cash Provided by/(Used in) Operating Activities**	46,093,305	38,618,510	19%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(126,206,543)	(82,645,360)	-53%
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	80,487,977	(127,967,110)	163%
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained below *)	(211,505)	(4,161,377)	95%
27	**Net Cash Provided by/(Used in) Investing Activities**	(45,930,071)	(214,773,847)	79%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt		180,000,000	-100%
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	(2,008,575)	(2,016,387)	0%
39	Preferred Stock			
40	Common Stock			
41	Other:			
42	Net Decrease in Short-Term Debt			
43	Dividends on Preferred Stock			
44	Dividends on Common Stock			
45	Other Financing Activities (explained below **)	(183,609)	(123,511)	-49%
46	**Net Cash Provided by (Used in) Financing Activities**	(2,192,184)	177,860,102	-101%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(2,028,950)	1,704,765	-219%
49	**Cash and Cash Equivalents at Beginning of Year**	2,033,125	4,175	48598%
50	**Cash and Cash Equivalents at End of Year**	4,175	1,708,940	-100%

*Long Term Notes Receivable, Officer Insurance, PEP Insurance CSV

**Unamortized Discount on Long-term Debt

Company Name: **Black Hills Power, Inc.** **SCHEDULE 24**

LONG TERM DEBT

Year: 2009

	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 Y	06/1988	06/2018	6,000,000	5,906,578	2,519,999	9.49%	256,037	10.16%
2									
3	Series Z	05/1991	05/2021	35,000,000	34,790,305	19,980,000	9.35%	1,939,986	9.71%
4									
5	Series AC	02/1995	02/2010	30,000,000	29,812,500	30,000,000	8.06%	2,418,000	8.06%
6									
7	Series AE	08/2002	08/2032	75,000,000	74,343,750	75,000,000	7.23%	5,484,806	7.31%
8									
9	Series AF	10/09	11/39	180,000,000	177,975,846	180,000,000	6.125%	11,098,812	6.17%
10									
11	2004 Pollution Control:								
12	Campbell Cty 4.8%	11/2004	10/2014	1,550,000	1,532,563	1,550,000	4.80%	77,710	5.01%
13	Campbell Cty 5.35%	11/2004	10/2024	12,200,000	12,062,750	12,200,000	5.35%	665,560	5.46%
14	Pennington Cty 4.8%	11/2004	10/2014	2,050,000	2,026,938	2,050,000	4.80%	102,777	5.01%
15	Weston Cty 4.8%	11/2004	10/2014	2,850,000	2,817,938	2,850,000	4.80%	142,885	5.01%
16									
17	1994 A Environ Improv Bond	06/1994	06/2024	3,000,000	2,930,057	2,855,000	8.00%	231,362	8.10%
18									
19	Bear Paw Energy	06/2000	05/2012	1,078,000	1,078,000	187,512	13.66%	30,510	16.27%
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			348,728,000	345,277,225	329,192,511		22,448,445	6.82%

PREFERRED STOCK

Year: 2009

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	N/A									
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
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26										
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29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2009

		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	23,416,396							

MONTANA EARNED RATE OF RETURN

Year: 2009

	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	Note: This schedule is not complete because			
31	Montana revenues represent less than			
32	2% of the Company's revenue.			
33				
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: 2009

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	1,390
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	(923)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	467
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	2,317
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	2,317
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	2,317
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	13
36		Commercial	22
37		Industrial	2
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	37
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	90,084
45		Average Annual Residential Cost per (Kwh) (Cents) *	8.30
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	546
48		Gross Plant per Customer	12.62

MONTANA CUSTOMER INFORMATION

Year: 2009

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

MONTANA EMPLOYEE COUNTS

Year: 2009

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

Company Name: **Black Hills Power, Inc.** **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

Year: 2010

	Project Description	Total Company	Total Montana
1	N/A		
2			
3			
4			
5			
6			
7			
8			
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46			
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48			
49			
50	**TOTAL**		

Company Name: **Black Hills Power, Inc.** SCHEDULE 32

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2009

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	14	1800	376	307,772	100,779
2	Feb.	27	1900	344	263,972	85,177
3	Mar.	11	800	357	287,031	101,015
4	Apr.	4	1100	301	293,015	120,425
5	May	19	1700	321	235,048	63,946
6	Jun.	25	1700	374	241,061	76,166
7	Jul.	23	1700	374	310,072	120,153
8	Aug.	13	1700	387	322,834	134,409
9	Sep.	16	1700	327	270,910	99,416
10	Oct.	13	1200	321	297,935	112,246
11	Nov.	23	1800	310	260,454	81,333
12	Dec.	8	1800	392	295,587	75,969
13	**TOTAL**				3,385,691	1,171,034

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.					
16	Mar.	*Peak information maintained on a total system basis only.				
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	1,582,353	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,640,176
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	185,444	for Resale	483,951
7	(Less) Energy for Pumping			
8	**NET Generation**	1,767,797	Non-Requirements Sales	
9	Purchases	1,673,486	for Resale	1,171,034
10	Power Exchanges			
11	Received	16,450	Energy Furnished	
12	Delivered	(72,039)	Without Charge	
13	**NET Exchanges**	(55,589)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	6,709,660	Electric Utility	11,758
16	Delivered	(6,709,660)		
17	**NET Transmission Wheeling**	-	Total Energy Losses	78,775
18	Transmission by Others Losses	-		
19	**TOTAL**	3,385,694	**TOTAL**	3,385,694

SOURCES OF ELECTRIC SUPPLY

Year: 2009

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	4,658
2					
3	Thermal	Ben French	Rapid City, SD	10	(310)
4					
5	Thermal	Ben French	Rapid City, SD	24	155,387
6					
7	Thermal	Osage	Osage, WY	35	233,158
8					
9	Thermal	Wyodak	Gillette, WY	69	542,706
10					
11	Thermal	Neil Simpson I	Gillette, WY	20	139,303
12					
13	Thermal	Neil Simpson II	Gillette, WY	84	650,519
14					
15	Thermal	Lange	Rapid City, SD	39	14,622
16					
17	Thermal	Neil Simpson CT 1	Gillette, WY	39	29,028
18					
19	Purchases	See Schedule 32			1,673,486
20					
21	Wheeling	See Schedule 32			-
22					
23	Total Interchange	See Schedule 32			(55,589)
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**			418	3386968

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2009

	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							
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21							
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26							
27							
28							
29							
30							
31							
32	**TOTAL**						

Company Name: Black Hills Power, Inc. 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: Black Hills Power, Inc. 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: 2009

	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	$7,100	$7,622	89	91	13	13
2	Commercial - Small	72,900	64,443	914	767	21	21
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	2,237,400	2,004,360	46,501	38,839	2	1
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**	$2,317,400	$2,076,425	47,504.0	39,697.0	36	35