Black Hills Power
Chris Kilpatrick
Director of Rates- Electric Regulation
Chris.Kilpatrick@blackhillscorp.com

625 Ninth Street• P.O. Box 1400
Rapid City, South Dakota 57709-1400
P: 605.721.2748
F: 605.721.2568

April 29, 2011

Public Service Commission
State of Montana
1701 Prospect Avenue
P.O. Box 202601
Helena, MT 59620-2601

Dear Public Service Commission of Montana:

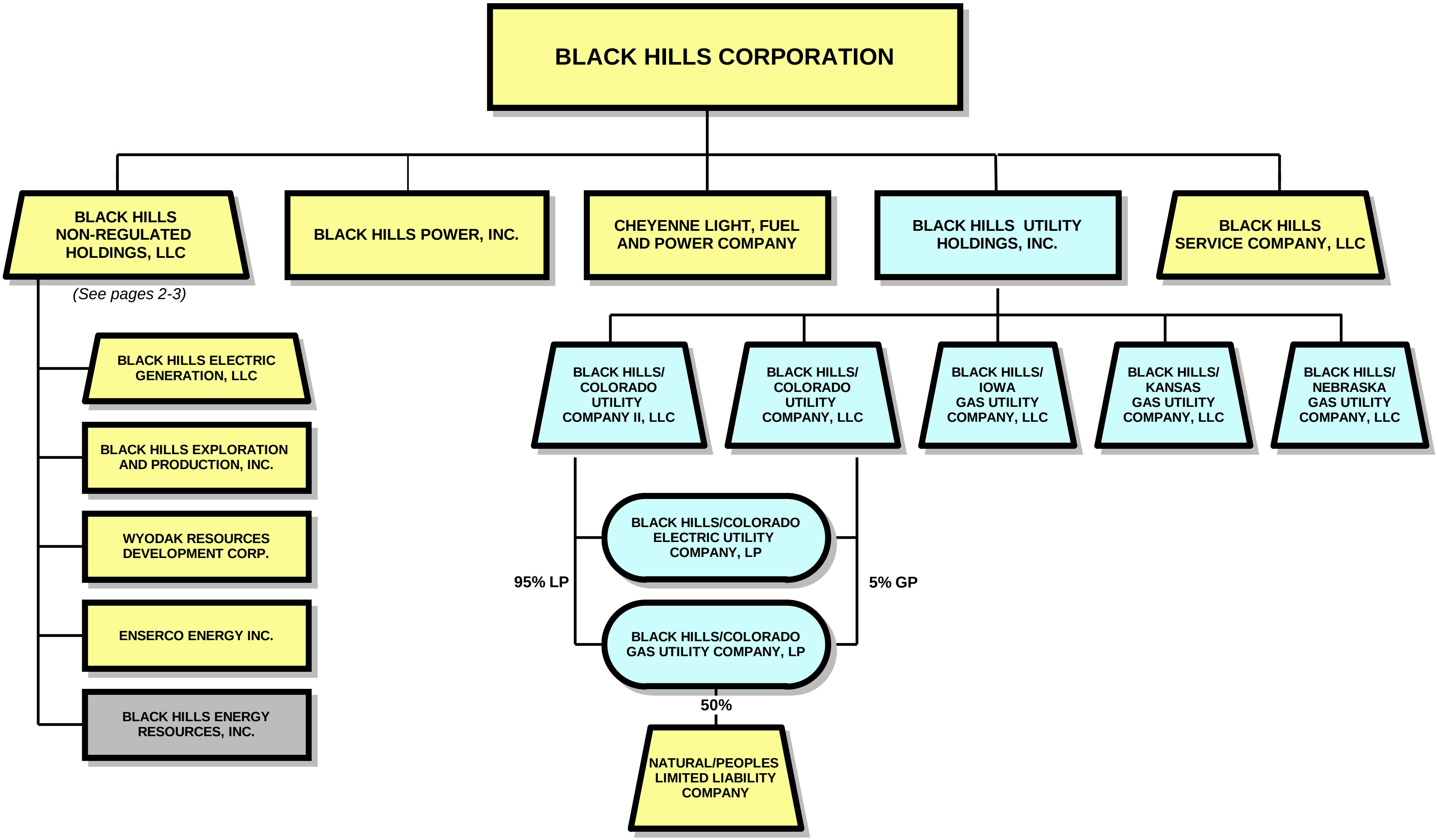
Enclosed please find the 2010 Black Hills Power Annual Report for Montana. Included with the report is the corporate structure chart.

If you have any questions, please contact me.

Sincerely,

Chris Kilpatrick

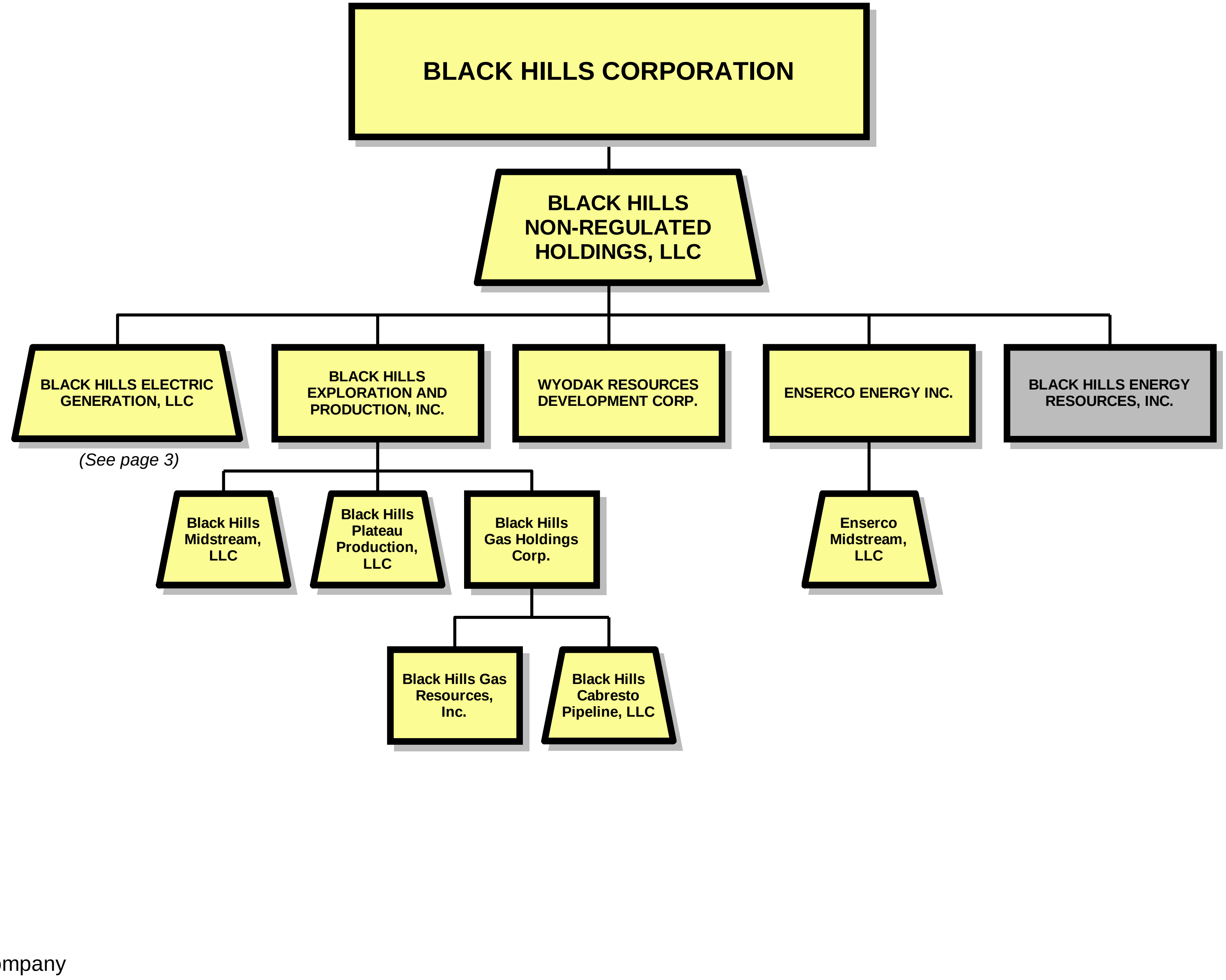
BLACK HILLS CORPORATION
ORGANIZATIONAL CHART



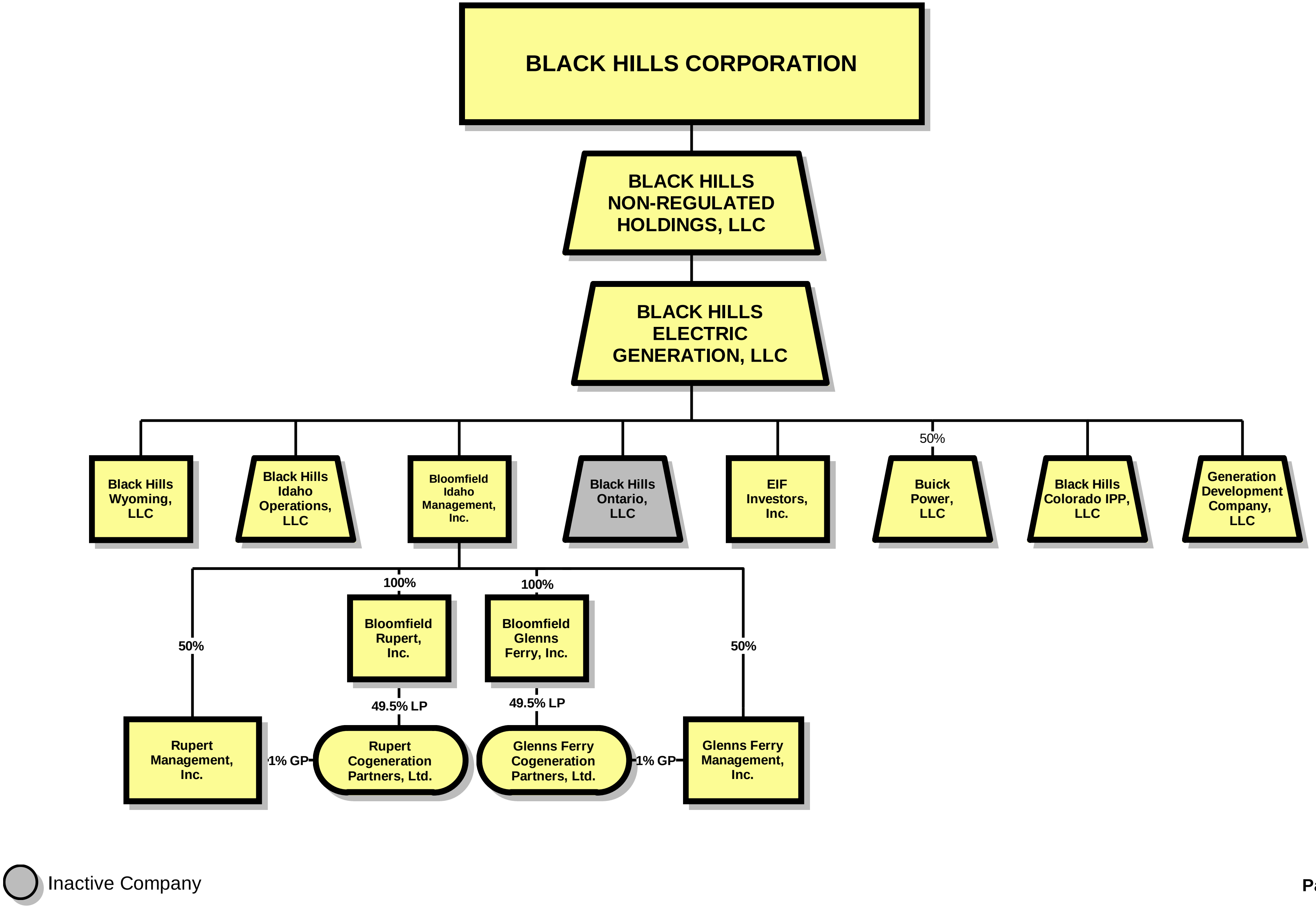
Doing business as ***BLACK HILLS ENERGY***

Inactive Company

BLACK HILLS CORPORATION ORGANIZATIONAL CHART



BLACK HILLS CORPORATION
ORGANIZATIONAL CHART



Company Name: **Black Hills Power, Inc.** **SCHEDULE 1**

IDENTIFICATION

Year: **2010**

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 - Resource Planning and Electric Rates
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	$66,625
3	John R. Howard	Rapid City, SD	62,250
4	Kay S. Jorgensen	Spearfish, SD	65,375
5	David C. Ebertz	Gillette, WY	59,750
6	Gary L. Pechota	Bethlehem, PA	62,250
7	Stephen D. Newlin	Avon Lake, OH	64,500
8	Jack W. Eugster	Excelsior, MN	65,750
9	Warren L Robinson	Rapid City, SD	73,500
10	John B. Vering (b)	Southlake, TX	25,000
11			
12	(a) Mr. Emery is officer of the company and is not compensated for his services		
13	as a director.		
14			
15	(b) Mr. Vering was only paid for his Board of Directors for part of the year as		
16	during the year he became interim President of a subsidiary company.		
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Company Name: Black Hills Power, Inc. **SCHEDULE 3**

Officers

Year: 2010

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	Senior Vice President, General Counsel, and CCO		Steven J. Helmers
5	Senior Vice President - Chief Information Officer		Scott A. Buchholz
6	Senior Vice President - Communication and Investor Relations		Lynnette K. Wilson
7	Senior Vice President - Human Resources		Robert A. Myers
8	Vice President - Governance and Corporate Secretary		Roxann R. Basham
9	Vice President - Strategic Initiatives		Stephen L. Pella *
10	Vice President - Supply Chain		Perry S. Krush
11	Vice President - Corporate Controller		Jeffrey B. Berzina
12	Vice President, Treasurer & Chief Risk Officer		Garner M. Anderson
13	Vice President - Regulatory and Governmental Affairs		Kyle D. White
14	Vice President - Strategic Planning & Development		Richard W. Kinzley
15	Vice President - Utility Operations		Stuart A. Wevik **
16	Vice President - Utility Services		Ivan Vancus ***
17	Vice President and General Manager - Power Delivery		Mark L. Lux ****
18	Vice President and General Manager - Gillette Complex		Gregory L. Hager
19	Vice President - Customer Service		Randy D. Winkelman
20	Vice President - BHP Operations		Richard C. Loomis
21	Vice President - Electric Regulatory Services		Brian G. Iverson
22	Vice President - Power Supply and Renewables Integration		Jacqueline A. Sargent *****
23			
24			
25	* Stephen L. Pella was appointed Vice President of Strategic Initiatives in August 2010.		
26			
27	** Stuart A. Wevik was appointed Vice President of Utility Operations in August 2010.		
28			
29	*** Ivan Vancas was appointed Vice President of Utility Services in August 2010.		
30			
31	**** Mark L. Lux position was changed to include General Manager of Power Delivery in August 2010.		
32			
33	***** Jacqueline A. Sargent was appointed Vice President of Power Supply and Renewables Integration		
34	in February 2010 and left the Company in August 2010.		
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Company Name: Black Hills Power, Inc. SCHEDULE 4

CORPORATE STRUCTURE

Year: 2010

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	31,267,992	100.00%
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42				100.00%
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50	**TOTAL**		31,267,992	

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

CORPORATE ALLOCATIONS

Year: 2010

	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: 2010

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)	13,867,822	23.98%	353,629
2	Enserco Energy, Inc	Gas Sales to Utility	Fair Market Value (based on similar arms-length transactions)	1,651,810	0.04%	42,121
3	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	8,664,024	6.10%	220,933
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32	**TOTAL**			24,183,656		616,683

Company Name: Black Hills Power, Inc. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2010

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	Wyodak Resources Development Corp.	Electricity	Wyoming Industrial Rate	1,195,706	100.00%	
2	Black Hills Wyoming	Transmission Service	Point to Point Open Access Transmission Tariff	778,701	100.00%	
3	Black Hills Wyoming	Non-Firm Energy Sales	Fair Market Value (Based on similar arms-length transactions)	10,864	100.00%	
4	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (Based on similar arms-length transactions)	1,200,090	1.47%	30,578
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32	**TOTAL**			3,185,361		30,578

BHP UTILITY INCOME STATEMENT

Year: 2010

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	201,802,829	230,227,106	14.09%
2				
3	Operating Expenses			
4	401 Operation Expenses	133,917,447	137,448,652	2.64%
5	402 Maintenance Expense	12,034,887	14,330,107	19.07%
6	403 Depreciation Expense	19,313,360	21,886,431	13.32%
7	404-405 Amortization of Electric Plant		32,286	-100.00%
8	406 Amort. of Plant Acquisition Adjustments	151,404	110,906	
9	407 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Credits (SD-ECA)	(5,030,633)	739,444	114.70%
11	408.1 Taxes Other Than Income Taxes	6,482,716	6,603,929	1.87%
12	409.1 Income Taxes - Federal	(3,949,426)	(14,896,058)	-277.17%
13	- Other	(9,843)	5,613	
14	410.1 Provision for Deferred Income Taxes	14,282,207	55,238,969	286.77%
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	(2,557,392)	(29,514,065)	-1054.07%
16	411.4 Investment Tax Credit Adjustments	(124,398)	(99,324)	20.16%
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**	174,510,329	191,886,890	9.96%
21	**NET UTILITY OPERATING INCOME**	27,292,500	38,340,216	40.48%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Electricity			
2	440 Residential	7,100	7,600	7.04%
3	442 Commercial & Industrial - Small	72,900	55,800	-23.46%
4	Commercial & Industrial - Large	2,237,400	2,428,900	8.56%
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**	2,317,400	2,492,300	7.55%
11	447 Sales for Resale			
12				
13	**TOTAL Sales of Electricity**	2,317,400	2,492,300	7.55%
14	449.1 (Less) Provision for Rate Refunds			
15				
16	**TOTAL Revenue Net of Provision for Refunds**	2,317,400	2,492,300	7.55%
17	Other Operating Revenues			
18	450 Forfeited Discounts & Late Payment Revenues	534	151	
19	451 Miscellaneous Service Revenues	8	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	159	
26	**Total Electric Operating Revenues**	2,317,942	2,492,459	7.53%

Company Name: Black Hills Power, Inc.

SCHEDULE 10

BHP OPERATION & MAINTENANCE EXPENSES

Year: 2010

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	1,366,693	1,519,687	11.19%
6	501 Fuel	20,400,617	20,371,360	-0.14%
7	502 Steam Expenses	3,771,286	5,185,786	37.51%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	989,442	1,300,438	31.43%
11	506 Miscellaneous Steam Power Expenses	1,270,753	1,663,077	30.87%
12	507 Rents		2,945,410	-100.00%
13				
14	TOTAL Operation - Steam	27,798,791	32,985,758	18.66%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	538,383	1,258,757	133.80%
18	511 Maintenance of Structures	261,149	650,399	149.05%
19	512 Maintenance of Boiler Plant	4,911,155	4,550,855	-7.34%
20	513 Maintenance of Electric Plant	2,106,352	1,239,194	-41.17%
21	514 Maintenance of Miscellaneous Steam Plant	834,242	635,610	-23.81%
22				
23	TOTAL Maintenance - Steam	8,651,281	8,334,815	-3.66%
24				
25	**TOTAL Steam Power Production Expenses**	36,450,072	41,320,573	13.36%
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: 2010

	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	58,761	105,007	78.70%
27	547	Fuel	3,405,502	2,252,409	-33.86%
28	548	Generation Expenses	381,333	446,704	17.14%
29	549	Miscellaneous Other Power Gen. Expenses	39,530	85,196	115.52%
30	550	Rents		111,694	-100.00%
31					
32		TOTAL Operation - Other	3,885,126	3,001,010	-22.76%
33					
34	Maintenance				
35	551	Maintenance Supervision & Engineering	73,522	119,603	62.68%
36	552	Maintenance of Structures	2,995	4,465	49.08%
37	553	Maintenance of Generating & Electric Plant	525,202	2,358,970	349.15%
38	554	Maintenance of Misc. Other Power Gen. Plant	23,333	39,243	68.19%
39					
40		TOTAL Maintenance - Other	625,052	2,522,281	303.53%
41					
42		**TOTAL Other Power Production Expenses**	4,510,178	5,523,291	22.46%
43					
44	Other Power Supply Expenses				
45	555	Purchased Power	52,032,648	46,362,379	-10.90%
46	556	System Control & Load Dispatching	426,015	536,914	26.03%
47	557	Other Expenses			
48					
49		TOTAL Other Power Supply Expenses	52,458,663	46,899,293	-10.60%
50					
51		**TOTAL Power Production Expenses**	93,418,913	93,743,157	0.35%

BHP OPERATION & MAINTENANCE EXPENSES

Year: 2010

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	650,441	693,618	6.64%
4	561	Load Dispatching	1,152,222	1,815,588	57.57%
5	562	Station Expenses	51,207	86,525	68.97%
6	563	Overhead Line Expenses	4,384	16,665	280.13%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	16,436,790	19,852,473	20.78%
9	566	Miscellaneous Transmission Expenses	172,752	143,265	-17.07%
10	567	Rents			
11					
12		TOTAL Operation - Transmission	18,467,796	22,608,134	22.42%
13	Maintenance				
14	568	Maintenance Supervision & Engineering		11	-100.00%
15	569	Maintenance of Structures			
16	570	Maintenance of Station Equipment	39,642	95,670	141.33%
17	571	Maintenance of Overhead Lines	65,243	44,047	-32.49%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant			
20					
21		TOTAL Maintenance - Transmission	104,885	139,728	33.22%
22					
23		**TOTAL Transmission Expenses**	18,572,681	22,747,862	22.48%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	927,555	893,239	-3.70%
28	581	Load Dispatching	135,669	199,809	47.28%
29	582	Station Expenses	456,565	465,326	1.92%
30	583	Overhead Line Expenses	772,644	625,105	-19.10%
31	584	Underground Line Expenses	224,904	276,605	22.99%
32	585	Street Lighting & Signal System Expenses	738	1,865	152.71%
33	586	Meter Expenses	371,428	373,875	0.66%
34	587	Customer Installations Expenses	17,871	34,953	95.59%
35	588	Miscellaneous Distribution Expenses	462,092	787,223	70.36%
36	589	Rents	22,500	22,500	
37					
38		TOTAL Operation - Distribution	3,391,966	3,680,500	8.51%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	10,188	25,017	145.55%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	151,137	203,193	34.44%
43	593	Maintenance of Overhead Lines	1,885,918	1,935,818	2.65%
44	594	Maintenance of Underground Lines	151,169	159,663	5.62%
45	595	Maintenance of Line Transformers	12,849	23,695	84.41%
46	596	Maintenance of Street Lighting, Signal Systems	132,013	140,614	6.52%
47	597	Maintenance of Meters	67,682	58,890	-12.99%
48	598	Maintenance of Miscellaneous Dist. Plant	44,895	135,696	202.25%
49					
50		TOTAL Maintenance - Distribution	2,455,851	2,682,586	9.23%
51					
52		**TOTAL Distribution Expenses**	5,847,817	6,363,086	8.81%

BHP OPERATION & MAINTENANCE EXPENSES

Year: 2010

	Account Number & Title		Last Year	This Year	% Change
1		Customer Accounts Expenses			
2	Operation				
3	901	Supervision	11,233	24,271	116.07%
4	902	Meter Reading Expenses	586,848	787,795	34.24%
5	903	Customer Records & Collection Expenses	1,173,248	2,188,415	86.53%
6	904	Uncollectible Accounts Expenses	315,616	360,666	14.27%
7	905	Miscellaneous Customer Accounts Expenses	565,625	573,843	1.45%
8					
9		TOTAL Customer Accounts Expenses	2,652,570	3,934,990	48.35%
10					
11		Customer Service & Information Expenses			
12	Operation				
13	907	Supervision	110,586	219,781	98.74%
14	908	Customer Assistance Expenses	798,690	1,008,287	26.24%
15	909	Informational & Instructional Adv. Expenses	12,502	11,933	-4.55%
16	910	Miscellaneous Customer Service & Info. Exp.	56,466	81,230	43.86%
17					
18		TOTAL Customer Service & Info Expenses	978,244	1,321,231	35.06%
19					
20		Sales Expenses			
21	Operation				
22	911	Supervision			
23	912	Demonstrating & Selling Expenses		506	-100.00%
24	913	Advertising Expenses			
25	916	Miscellaneous Sales Expenses		250	-100.00%
26					
27		TOTAL Sales Expenses		756	-100.00%
28					
29		Administrative & General Expenses			
30	Operation				
31	920	Administrative & General Salaries	12,000,679	8,793,348	-26.73%
32	921	Office Supplies & Expenses	4,688,341	4,105,478	-12.43%
33	922	(Less) Administrative Expenses Transferred - Cr.	(22,979)	(14,496)	36.92%
34	923	Outside Services Employed	2,411,391	2,457,187	1.90%
35	924	Property Insurance	526,595	904,602	71.78%
36	925	Injuries & Damages	1,181,058	1,061,725	-10.10%
37	926	Employee Pensions & Benefits	1,793,377	3,513,499	95.92%
38	927	Franchise Requirements			
39	928	Regulatory Commission Expenses	484,022	826,060	70.67%
40	929	(Less) Duplicate Charges - Cr.			
41	930.1	General Advertising Expenses	174,910	266,833	52.55%
42	930.2	Miscellaneous General Expenses	738,503	717,716	-2.81%
43	931	Rents	308,395	385,017	24.85%
44					
45		TOTAL Operation - Admin. & General	24,284,292	23,016,969	-5.22%
46	Maintenance				
47	935	Maintenance of General Plant	197,817	650,708	228.94%
48					
49		**TOTAL Administrative & General Expenses**	24,482,109	23,667,677	-3.33%
50					
51		**TOTAL Operation & Maintenance Expenses**	145,952,334	151,778,759	3.99%

Company Name: Black Hills Power, Inc. SCHEDULE 11

MONTANA TAXES OTHER THAN INCOME

Year: 2010

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	1,545	1,567	1.42%
5	Montana PSC	5,698	8,153	43.09%
6	Franchise Taxes			
7	Property Taxes	115,321	172,612	49.68%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	6,993	7,446	6.48%
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51	**TOTAL MT Taxes Other Than Income**	129,557	189,778	46.48%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2010

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

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2010

	Description	Total Company	Montana	% Montana
1	None.			
2				
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49				
50	**TOTAL Contributions**			

Pension Costs

Year: 2010

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	55,615,376	51,964,624	-6.56%
8	Service cost	1,214,408	1,155,240	-4.87%
9	Interest Cost	3,280,041	3,143,245	-4.17%
10	Plan participants' contributions	-		
11	Amendments	1,374,150	1,026,379	-25.31%
12	Actuarial Gain	(1,258,269)	1,686,211	234.01%
13	Acquisition			
14	Benefits paid	(2,472,310)	(3,360,323)	-35.92%
15	Benefit obligation at end of year	57,753,396	55,615,376	-3.70%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	39,039,528	32,100,429	-17.77%
18	Actual return on plan assets	5,361,041	9,409,785	75.52%
19	Acquisition			
20	Employer contribution	6,299,644		-100.00%
21	Plan participants' contributions	-	(85,898)	100.00%
22	Benefits paid	(2,472,310)	(2,384,788)	3.54%
23	Fair value of plan assets at end of year	48,227,903	39,039,528	-19.05%
24	**Funded Status**	(9,525,493)	(31,736,491)	-233.17%
25	Unrecognized net actuarial loss	17,663,686	38,485,937	117.88%
26	Unrecognized prior service cost	385,649	409,002	6.06%
27	Prepaid (accrued) benefit cost	8,523,842	7,158,448	-16.02%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	6.05%	6.29%	3.88%
31	Expected return on plan assets	8.00%	8.50%	6.25%
32	Rate of compensation increase	4.25%	4.25%	
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	1,271,224	1,344,440	5.76%
36	Interest cost	3,280,041	3,143,245	-4.17%
37	Expected return on plan assets	(3,008,272)	(2,780,274)	7.58%
38	Amortization of prior service cost	62,159	87,030	40.01%
39	Recognized net actuarial loss	1,377,517	1,585,834	15.12%
40	Net periodic benefit cost	2,982,669	3,380,275	13.33%
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	1,247	1,257	0.80%
48	Not Covered by the Plan	52	51	-1.92%
49	Active	813	840	3.32%
50	Retired	190	183	-3.68%
51	Deferred Vested Terminated	192	183	-4.69%

Other Post Employment Benefits (OPEBS)

Year: 2010

	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	5.00%	6%	22.00%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	10.00%	9.00%	-10.00%
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	
11	Rate of compensation increase			
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	7,978,048	7,121,236	-10.74%
20	Service cost	209,786	376,891	79.65%
21	Interest Cost	365,143	596,646	63.40%
22	Plan participants' contributions	-		
23	Amendments			
24	Actuarial Gain	(151,115)	55,867	136.97%
25	Acquisition			
26	Benefits paid	(426,121)	(172,592)	59.50%
27	Benefit obligation at end of year	7,975,741	7,978,048	0.03%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	(964,842)	(792,250)	17.89%
30	Actual return on plan assets			
31	Acquisition			
32	Employer contribution			
33	Plan participants' contributions	-	-	
34	Benefits paid	(426,121)	(172,592)	59.50%
35	Fair value of plan assets at end of year	(1,390,963)	(964,842)	30.63%
36	**Funded Status**	(9,366,704)	(8,942,890)	4.52%
37	Unrecognized net actuarial loss			
38	Unrecognized prior service cost			
39	Prepaid (accrued) benefit cost	(9,366,704)	(8,942,890)	4.52%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	209,786	376,891	79.65%
42	Interest cost	365,143	596,646	63.40%
43	Expected return on plan assets	-	-	
44	Amortization of prior service cost			
45	Recognized net actuarial loss	(151,115)	55,867	136.97%
46	Net periodic benefit cost	423,814	1,029,404	142.89%
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: 2010

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	1,192	1,190	-0.17%
3	Not Covered by the Plan			
4	Active	992	996	0.40%
5	Retired	107	102	-4.67%
6	Spouses/Dependants covered by the Plan	93	92	-1.08%
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: 2010

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: 2010

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						

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, 2010, 2009 and 2008. We have no employment agreements with our Named Executive Officers. Mr. Cleberg joined us on July 16, 2008.

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	2010	$588,924	$605,554	$672,000	$766,046	$ 60,138	$2,692,662
Chairman, President	2009	$564,000	$674,723	$221,088	$361,799	$ 51,990	$1,873,600
and Chief Executive Officer	2008	$563,269	$867,400	$205,296	$549,730	$ 42,293	$2,227,988
Anthony S. Cleberg	2010	$321,923	$288,372	$234,000	—	$149,607	$ 993,902
Executive Vice President	2009	$315,000	$321,300	$ 79,380	$102,058	$198,778	$1,016,516
and Chief Financial Officer	2008	$130,846	$225,000	$ 34,020	$ 3,645	$ 25,911	$ 419,422
Linden R. Evans	2010	$333,538	$365,257	$288,000	—	$148,397	$1,135,192
President and Chief	2009	$274,000	$406,978	$ 76,720	$102,553	$ 29,086	$ 889,337
Operating Officer—Utilities	2008	$273,212	$395,908	$ 71,240	$125,292	$ 24,421	$ 890,073
Thomas M. Ohlmacher	2010	$353,769	$365,257	$284,000	$734,583	$ 43,383	$1,780,992
President and Chief	2009	$351,000	$406,978	$ 98,280	$312,019	$ 35,125	$1,203,402
Operating Officer— Non-regulated Energy	2008	$350,600	$466,020	$ 91,260	$292,809	$ 28,915	$1,229,604
Steven J. Helmers	2010	$276,923	$249,918	$179,200	$178,390	$ 74,271	$ 958,702
Senior Vice President	2009	$270,000	$278,462	$ 76,720	$113,474	$ 26,231	$ 764,887
and General Counsel	2008	$269,604	$265,550	$ 49,140	$121,460	$ 21,648	$ 727,402

(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, 2010. 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:

	2010	2009	2008
David R. Emery	$823,477	$944,509	$1,105,450
Anthony S. Cleberg	$392,150	$449,766	$ 225,000
Linden R. Evans	$496,698	$569,717	$ 490,714
Thomas M. Ohlmacher	$496,698	$569,717	$ 616,785
Steven J. Helmers	$339,854	$389,802	$ 329,375

(2) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Annual Incentive Plan. The Compensation Committee approved the payout of the 2010 awards at its January 26, 2011, meeting and the awards were paid on March 4, 2011.

(3) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Defined Benefit Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective year.

The Defined Benefit Pension Plan and PRB were frozen as of December 31, 2009 for participants that did not satisfy the age 45 and 10 years of service eligibility. Messrs. Cleberg, Evans and Helmers did not meet the eligibility choice criteria and their Defined Pension and PRB benefits were frozen. In 2008, Mr. Cleberg did not meet the one year service requirement to be in the Defined Benefit Plan. The amounts for 2008 were annualized due to the change in ASC 715 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"). Messrs. Emery, Ohlmacher and Helmers are participants in the Grandfathered PEP and 2005 PEP. The 2007 PEP was eliminated effective January 1, 2010 and was replaced with employer contributions into a Nonqalified Deferred Compensation Plan ("NQDC"). The NQDC employer contributions are reported in the All Other Compensation column. Messrs. Cleberg and Evans were the only Named Executive Officers participating in the 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.

	Year	Defined Benefit Plan	PRB	PEP	Total Change in Pension Value
David R. Emery	2010	$ 88,118	$369,162	$ 308,766	$766,046
	2009	$ 43,690	$167,024	$ 151,085	$361,799
	2008	$ 33,858	$264,299	$ 251,573	$549.730
Anthony S. Cleberg	2010	$ 3,713	$ 2,660	$ (52,506)	—
	2009	$ 36,790	$ 12,762	$ 52,506	$102,058
	2008	—	$ 3,645	—	$ 3,645
Linden R. Evans	2010	$ 22,976	$ 19,195	$(163,783)	—
	2009	$ 25,375	$ 24,629	$ 52,549	$102,553
	2008	$ 19,368	$ 48,132	$ 57,792	$125,292
Thomas M. Ohlmacher	2010	$218,327	$323,252	$ 193,004	$734,583
	2009	$131,901	$ 96,327	$ 83,791	$312,019
	2008	$101,389	$109,258	$ 82,162	$292,809
Steven J. Helmers	2010	$ 28,263	$ 18,239	$ 131,888	$178,390
	2009	$ 34,129	$ 18,295	$ 61,050	$113,474
	2008	$ 26,157	$ 22,526	$ 72,777	$121,460

(4) All Other Compensation includes amounts allocated under the 401(k) match, defined contributions, NQDC contributions, dividends received on restricted stock and unvested restricted stock units and perquisites. 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.

	Year	401(k) Match	Defined Contri-bution	NQDC Contri-bution	Dividends on Restricted Stock/Units	Perquisites	Total Other Compensation
David R. Emery	2010	$14,700	—	—	$37,378	$8,060	$ 60,138
Anthony S. Cleberg	2010	$14,700	$7,350	$100,347	$18,484	$8,726	$149,607
Linden R. Evans	2010	$14,700	$7,350	$ 96,925	$21,824	$7,598	$148,397
Thomas M. Ohlmacher	2010	$14,700	—	—	$20,989	$7,694	$ 43,383
Steven J. Helmers	2010	$14,700	$7,350	$ 31,935	$14,859	$5,427	$ 74,271

PROXY STATEMENT

BALANCE SHEET

Year: 2010

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	733,274,130	751,226,307	-2%
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	17,788,960	177,978,541	-90%
9	107 Construction Work in Progress - Electric	201,783,516	35,704,655	465%
10	108 (Less) Accumulated Depreciation	(311,816,383)	(324,433,412)	4%
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.	(2,826,211)	(2,937,117)	4%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	643,074,320	642,409,282	0%
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	4,306,695	4,493,899	-4%
23	125 Sinking Funds			
24	**TOTAL Other Property & Investments**	4,308,357	4,495,561	-4%
25				
26	**Current & Accrued Assets**			
27	131 Cash	1,704,765	2,040,659	-16%
28	132-134 Special Deposits			
29	135 Working Funds	4,175	4,175	
30	136 Temporary Cash Investments			
31	141 Notes Receivable	37,787	17,448	117%
32	142 Customer Accounts Receivable	18,277,962	16,011,944	14%
33	143 Other Accounts Receivable	1,294,824	7,296,436	-82%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(258,522)	(230,060)	-12%
35	145 Notes Receivable - Associated Companies	57,783,244	39,955,209	45%
36	146 Accounts Receivable - Associated Companies	4,145,756	6,891,040	-40%
37	151 Fuel Stock	7,127,972	7,135,764	0%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	11,675,422	13,589,713	-14%
41	155 Merchandise			
42	156 Other Material & Supplies	100	100	
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed	21,637	533,690	-96%
45	165 Prepayments	1,460,374	3,617,542	-60%
46	171 Interest & Dividends Receivable			
47	172 Rents Receivable			
48	173 Accrued Utility Revenues	5,547,053	7,580,915	-27%
49	174 Miscellaneous Current & Accrued Assets			
50	**TOTAL Current & Accrued Assets**	108,822,549	104,444,575	4%

BALANCE SHEET

Year: 2010

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Assets and Other Debits (cont.)**			
3				
4	**Deferred Debits**			
5				
6	181 Unamortized Debt Expense	3,419,329	3,238,032	6%
7	182.1 Extraordinary Property Losses			
8	182.2 Unrecovered Plant & Regulatory Study Costs			
9	183 Prelim. Survey & Investigation Charges	295,878	328,007	-10%
10	184 Clearing Accounts	451,166	117,954	282%
11	185 Temporary Facilities			
12	186 Miscellaneous Deferred Debits	258,044	(54,318)	575%
13	187 Deferred Losses from Disposition of Util. Plant			
14	188 Research, Devel. & Demonstration Expend.			
15	189 Unamortized Loss on Reacquired Debt	2,206,352	3,015,994	-27%
16	190 Accumulated Deferred Income Taxes	51,058,199	64,706,672	-21%
17	**TOTAL Deferred Debits**	57,688,968	71,352,341	-19%
18				
19	**TOTAL Assets & Other Debits**	813,894,194	822,701,759	-1%
	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	216,419,980	247,687,972	-13%
35	217 (Less) Reacquired Capital Stock	(1,213,092)	(1,261,746)	4%
36	**TOTAL Proprietary Capital**	278,198,213	309,417,551	-10%
37				
38	**Long Term Debt**			
39				
40	221 Bonds	307,499,999	255,000,000	21%
41	222 (Less) Reacquired Bonds			
42	223 Advances from Associated Companies			
43	224 Other Long Term Debt	21,692,512	21,622,173	0%
44	225 Unamortized Premium on Long Term Debt			
45	226 (Less) Unamort. Discount on L-Term Debt-Dr.	(123,510)	(119,370)	-3%
46	**TOTAL Long Term Debt**	329,069,001	276,502,803	19%

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS
December 31, 2010, 2009 and 2008

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc. (the Company, "we," "us" or "our") is an electric utility serving customers in South Dakota, Wyoming and Montana. We are a wholly-owned subsidiary of Black Hills Corporation (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 the Company's ownership interests in the assets, liabilities and expenses of its jointly owned facilities (Note 4).

The financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). Additionally, these ·uirements differ from GAAP related to the presentation of certain items including deferred income taxes, and cost of removal lities. The Company's notes to the financial statements are prepared in conformity with GAAP. Accordingly, certain footnotes are ..ot reflective of the Company's FERC basis financial statements contained herein.

The Statement of Cash Flows for 2009 has been modified to reflect a break out of notes receivable and notes payable between our cash flows from operating activities and financing 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. 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 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.

Our regulatory assets and liabilities for which we recover the costs, but we do not earn a return were as follows as of December 31 (in thousands):

	Recovery Period	2010	2009
Regulatory assets:			
Unamortized loss on reacquired debt	14 years	$ 3,016	$ 2,207
AFUDC	Up to 45 years	9,489	7,579
Defined benefit postretirement plans	Up to 13 years	18,049	21,024
Deferred energy costs	Less than one year	3,584	7,467
Flow through accounting	Up to 35 years	4,772	—
Other		2,414	495
Total regulatory assets		$ 41,324	$ 38,772
Regulatory liabilities:			
Cost of removal for utility plant	Up to 53 years	$ 15,429	$ 13,678
Defined benefit postretirement plans	Up to 13 years	10,204	—
Other		4,575	2,515
Total regulatory liabilities		$ 30,208	$ 16,193

ılatory assets are primarily recorded for the probable future revenue to recover the costs associated with defined benefit ›tretirement 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 Sheets. Regulatory liabilities are included in Regulatory liabilities, current and Regulatory liabilities, non-current on the accompanying Balance Sheets.

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. Our AFUDC for the years ended December 31 was as follows (in thousands):

	2010	2009	2008
AFUDC - borrowed	$ 2,224	$ 4,357	2,556
AFUDC - equity	2,748	5,831	3,605
Total AFUDC	$ 4,972	$ 10,188	$ 6,161

Cash Equivalents

''e 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 receivable 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.

Accounts receivable consist of sales to residential, commercial, industrial, municipal and other customers all of which do not bear interest. These accounts receivables are stated at billed amounts net of write-offs or payment received. Approximately 26% of the accounts receivable balance consists of unbilled revenue.

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollected. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including unbilled revenue. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collection success given the existing collections environment.

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

	2010	2009
Accounts receivable trade	$ 21,365	$ 14,703
Unbilled revenues	7,581	5,547
Total accounts receivable - customers	28,946	20,250
Allowance for doubtful accounts	(230)	(259)
Net accounts receivable	$ 28,716	$ 19,991

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.

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 are computed on a straight-line basis using an annual composite rate of 2.2% in 2010, 2.8% in 2009 and 3.2% in 2008.

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 allow hedge accounting for qualifying fair value and cash flow hedges. Gain or loss on a derivative instrument designated and qualifying as a fair value hedging instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk should be recognized currently in earnings in the same accounting period. Conversely, the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument should be reported as a component of other comprehensive income, 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 ing amount of the long-lived assets, we would recognize an impairment loss. No impairment loss was recorded during 2010, 9 or 2008.

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.

(2) RECENTLY ADOPTED AND RECENTLY ISSUED ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

Disclosures About the Credit Quality of Financing Receivables and the Allowance for Credit Losses, ASC 310-10-50

In July 2010, the FASB issued an amendment to ASC 310-10-50, Receivables - Disclosures. The guidance requires additional disclosures that will facilitate financial statement user's evaluation of the nature of credit risk inherent in financing receivables, how that risk is analyzed in arriving at the allowance for credit losses, and the reason for any changes in the allowance for credit losses. These disclosures should be provided on a disaggregated basis but exempts trade receivables that have a contractual maturity of one year or less, receivables measured at lower of cost or fair value, and receivables measured at fair value with the changes in fair value reported in earnings. (See Note 1) It is effective for interim and annual reporting periods ending on or after December 15, 2010.

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

In June 2009, the FASB issued a revision regarding consolidations. The amendment requires a company to consider whether an entity that is insufficiently capitalized or is not controlled through voting should be consolidated. It requires 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 with ongoing re-evaluation. The adoption of this standard in January 2010 did not have any impact on our financial statements, results of operations, and cash flows.

'ently Issued Accounting Standards and Legislation

ratient Protection and Affordable Care Act (PPACA)

In March 2010, the President of the United States signed into law comprehensive healthcare reform legislation under the PPACA as amended by the Healthcare and Education Reconciliation Act. The potential impact on the Company, if any, cannot be determined until regulations are promulgated under the PPACA. Included among the provisions of the PPACA is a change in the tax treatment of the Medicare Part D subsidy (the "subsidy") which affects our Non-Pension Postretirement Benefit Plan. Internal Revenue Code Section 139A has been amended to eliminate the deduction of the subsidy in reducing income for years beginning after December 31, 2012. The impact of this change in the tax treatment of the subsidy had an immaterial effect on our financial position, results of operations and cash flows. The Company will continue to assess the accounting implications of the PPACA as related regulations and interpretations become available.

(3) PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2010	December 31, 2010 Weighted Average Useful Life	December 31, 2009	December 31, 2009 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 475,762	50	$ 336,534	53	30-62
Transmission	116,056	43	86,841	44	35-55
Distribution	271,470	37	264,847	37	15-65
Plant acquisition adjustment	4,870	32	4,870	32	32
General	58,777	22	55,701	22	10-50
Total electric plant	926,935		748,793		
Less accumulated depreciation and amortization	304,800		293,823		
Electric plant net of accumulated depreciation and amortization	622,135		454,970		
Construction work in progress	35,705		201,784		
ɛt electric plant	$ 657,840		$ 656,754		

(4) 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 (the 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. Our investment in the Plant and accumulated depreciation is included in the corresponding captions in the accompanying Balance Sheets. Our share of direct expenses of the Plant is included in the corresponding categories of operating expenses in the accompanying Statements of Income.

- We 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 investment in the transmission tie and accumulated depreciation is included in the corresponding captions in the accompanying Balance Sheets.

- We own a 52% interest in the Wygen III power plant. MDU owns 25% which was purchased in April 2009. At closing, MDU made a payment to us for its 25% share of the costs to date on the ongoing construction of the facility and subsequently reimbursed us for 25% of the total costs paid to complete the project. Our share of direct expenses of the jointly-owned facility are included in Operating expenses in the Statements of Income. Our share of property, plant and equipment in Wygen III and associated accumulated depreciation is included in the corresponding captions in the accompanying Balance Sheets.

- The City of Gillette owns a 23% interest in the Wygen III power plant which was purchased in July 2010 for $62.0 million. Wygen III was placed into commercial operations on April 1, 2010. Our share of direct expenses of the jointly-owned facility are included in Operating expenses in the Statements of Income. Our share of property, plant and equipment in Wygen III and associated accumulated depreciation is included in the corresponding captions in the accompanying Balance Sheets.

Our share of direct expenses related to our jointly owned plants for the years ended December 31 was as follows (dollars in thousands):

Share of Direct Expenses	Ownership Percentage	2010	2009	2008
Wyodak Plant	20.0%	$ 8,546	$ 8,021	$ 8,000
Transmission Tie	35.0%	$ 154	$ 100	$ 123
Wygen III (a)	52.0%	$ 7,618	$ —	$ —

(a) The Wygen III plant commenced commercial operations on April 1, 2010.

As of December 31, 2010, our interests in jointly-owned generating facilities and transmission systems included on our Balance Sheets were as follows (dollars in thousands):

Share of Direct Expenses	Ownership Percentage	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	20.0%	$ 82,466	$ 21,687	$ 54,108
Transmission Tie	35.0%	$ 19,644	$ —	$ 4,111
Wygen III (a)	52.0%	$ 129,340	$ 194	$ 2,282

(a) The Wygen III plant commenced commercial operations on April 1, 2010.

(5) 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, 2010, 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):

	December 31, 2009
Notional*	232,500
Maximum terms in months	10
Current derivative liabilities	$ 5
Pre-tax accumulated other comprehensive loss	$ (5)

* Gas in MMbtus

(6) LONG-TERM DEBT

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

	December 31, 2010	December 31, 2009
First mortgage bonds:		
8.06% due 2010	$ —	$ 30,000
9.49% due 2018	—	2,520
9.35% due 2021	—	19,980
7.23% due 2032	75,000	75,000
6.125% due 2039	180,000	180,000
Unamortized discount on 6.125% bonds	(119)	(124)
	254,881	307,376
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	2,972	3,043
	21,622	21,693
Total long-term debt	276,503	329,069
Less current maturities	(81)	(32,025)
Net long-term debt	$ 276,422	$ 297,044

Bond Issuance

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 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, and to redeem the Series AC mortgage bonds. Deferred finance costs of approximately $2.2 million were capitalized and are being amortized over the term of the bonds. Amortization of deferred financing costs is included in Interest expense.

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.

Series AC Bonds

In February 2010, the Series 8.06% AC bonds matured. These were paid in full for $30.0 million of principal plus accrued interest of $1.2 million.

Series Y Bonds

In March 2010, we completed redemption of our Series Y 9.49% bonds in full. The bonds were originally due in 2018. A total of \$2.7 million was paid on March 31, 2010, which includes the principal balance of \$2.5 million plus accrued interest and an early redemption premium of 2.618%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Balance Sheet and is being amortized over the remaining term of the original bonds.

Series Z Bonds

In June 2010, we completed redemption of our Series Z 9.35% bonds in full. The bonds were originally due in 2021. A total of \$21.8 million was paid on June 1, 2010, which included the principal balance of \$20.0 million plus accrued interest and an early redemption premium of 4.675%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Balance Sheet and is being amortized over the remaining term of the original bonds.

Long-term Debt Maturities

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

2011	$ 81
2012	$ 36
2013	$ —
2014	$ 6,450
2015	$ —
Thereafter	$ 270,055

(7) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	December 31, 2010 Carrying Value	December 31, 2010 Fair Value	December 31, 2009 Carrying Value	December 31, 2009 Fair Value
Cash and cash equivalents	$ 2,045	$ 2,045	$ 1,709	$ 1,709
Derivative financial instruments - Accrued liabilities	$ —	$ —	$ 5	$ 5
Long-term debt, including current maturities	$ 276,503	$ 301,964	$ 329,069	$ 344,942

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

e instruments are carried at fair value. Descriptions of the instruments we use are included in Note 5.

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.

(8) INCOME TAXES

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

	December 31, 2010	December 31, 2009	December 31, 2008
Current	$ (14,885)	$ (3,296)	$ (6,521)
Deferred	25,626	11,600	16,072
Total income tax expense	$ 10,741	$ 8,304	$ 9,551

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

	December 31, 2010	December 31, 2009
Deferred tax assets, current:		
Asset valuation reserve	$ 217	$ 90
Employee benefits	803	946
Rate refund	428	—
Other	—	2
Total deferred tax assets, current	1,448	1,038
Deferred tax liabilities, current:		
Prepaid expenses	(251)	(214)
Deferred costs	(2,056)	(2,677)
Total deferred tax liabilities, current	(2,307)	(2,891)
Net deferred tax assets (liabilities), current	$ (859)	$ (1,853)
Deferred tax assets, non-current:		
Plant related differences	$ 909	$ 1,151
Regulatory liabilities	10,074	7,847
Employee benefits	3,547	3,468
Net operating loss	9,147	—
Items of other comprehensive income	225	175
Research and development credit	1,613	1,038
Other	—	128
Total deferred tax assets, non-current	25,515	13,807
Deferred tax liabilities, non-current:		
Accelerated depreciation and other plant related differences	(132,338)	(93,253)
AFUDC	(6,168)	(4,926)
Regulatory assets	(5,557)	(10,011)
Employee benefits	(2,983)	(1,052)
Other	(788)	(772)
Total deferred tax liabilities, non-current	(147,834)	(110,014)
Net deferred tax assets (liabilities), non-current	$ (122,319)	$ (96,207)
Net deferred tax assets (liabilities)	$ (123,178)	$ (98,060)

The following table reconciles the change in the net deferred income tax assets (liabilities) from December 31, 2009 to December 31, 2010 and from December 31, 2008 to December 31, 2009 to deferred income tax expense (benefit) (in thousands):

	2010	2009
Change in deferred income tax assets (liabilities)	$ 25,118	$ 11,824
Deferred taxes related to regulatory assets and liabilities	9,272	(1,323)
Deferred taxes associated with other comprehensive income	(2,141)	(73)
Deferred taxes related to property basis differences	(4,713)	2,851
Deferred taxes related to AFUDC	(1,910)	(1,679)
Other	—	—
Deferred income tax expense (benefit) for the period	$ 25,626	$ 11,600

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

	December 31, 2010	December 31, 2009	December 31, 2008
Federal statutory rate	35.0%	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.6)	(0.9)	(0.7)
ity AFUDC	(2.0)	(6.2)	(3.6)
w through adjustments *	(7.4)	—	—
Other	0.6	(1.5)	(1.1)
	25.6%	26.4%	29.6%

* The flow-through adjustments relate primarily to an accounting method change for tax purposes that was filed with the 2008 tax return and for which consent was received from the IRS in September 2009. The effect of the change allows us to take a current tax deduction for repair costs that were previously capitalized for tax purposes. These costs will continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred during 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. Due to this regulatory treatment, we recorded an income tax benefit that was attributable to the 2008 through 2010 tax years. For years prior to 2008, we did not record a regulatory asset for the repairs deduction as the tax benefit was not flowed through to customers.

The accounting standards for uncertain tax positions 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):

	2010	2009
Unrecognized tax benefits at January 1	$ 3,877	$ 767
Additions for prior year tax positions	130	3,110
Reductions for prior year tax positions	(913)	—
Unrecognized tax benefits at December 31	$ 3,094	$ 3,877

The reduction for prior year tax positions relate to the reversal through otherwise allowed tax depreciation. The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $1.1 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, 2010 and 2009, the interest expense recognized related to income tax matters was not material to our financial results.

The Company files income tax returns in the United States federal jurisdiction as a member of the BHC consolidated group. The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the 'ration of statutes of limitations prior to December 31, 2011.

At December 31, 2010, we have federal NOL carry forward of $26.1 million which will expire in 2030. Ultimate usage of this NOL depends upon our future taxable income.

(9) COMPREHENSIVE INCOME

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

	December 31, 2010		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustment	$ (145)	$ 51	$ (94)
Reclassification adjustments of cash flow hedges settled and included in net income	64	(23)	41
Net change in fair value of derivatives designated as cash flow hedges	6	(2)	4
Other comprehensive loss	$ (75)	$ 26	$ (49)

	December 31, 2009		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum 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

	December 31, 2008		
	Pre-tax Amount	Tax Benefit	Net-of-tax Amount
Minimum 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)

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

	December 31, 2010	December 31, 2009
Derivatives designated as cash flow hedges	$ (848)	$ (893)
Employee benefit plans	(414)	(320)
Total accumulated other comprehensive loss	$ (1,262)	$ (1,213)

(10) EMPLOYEE BENEFIT PLANS

Funded Status of Benefit Plans

The funded status of postretirement benefit plan is required to be recognized in the statement of financial position. The funded status for pension plan is measured as the difference between the projected benefit obligation and the fair value of plan assets. The funded status for all other benefit plans is measured as the difference between the accumulated benefit obligation and the fair value of plan assets. A liability is recorded for an amount by which the benefit obligation exceeds the fair value of plan assets or an asset is recorded for any amount by which the fair value of plan assets exceeds the benefit obligation.

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 ("Pension Plan") covering employees who meet certain eligibility ·irements. The benefits are based on years of service and compensation levels during the highest five consecutive years of the last ears of service. Our funding policy is in accordance with the federal government's funding requirements. The Pension 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 Pension Plan.

In July 2009, the Board of Directors approved a partial freeze to the Pension Plan for all participants with the exception of bargaining unit participants. The freeze eliminated new non-bargaining unit employees from participation in the Pension Plan and froze the benefits of current non-bargaining unit participants except for the following group: those non-bargaining unit participants who are both 1) 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 the Company's 401(k) retirement savings plan. As a result of this action, we recognized a pre-tax curtailment expense of approximately $0.2 million in the third quarter of 2009.

In September of 2010, our bargaining unit employees voted to freeze participation in the Pension Plan and to freeze the benefits of current bargaining unit participants except for the following group: those bargaining unit participants who are both 1) age 45 or older as of December 31, 2010 and have 10 years or more of credited service as of January 1, 2011; 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 the Company's 401(k) retirement savings plan. The change is effective January 1, 2011. As a result of this action, we recognized a pre-tax curtailment expense of less than $0.1 million that was recognized in the fourth quarter of 2010.

The Pension 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 Pension 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 9.25% and 9.50% for the 2010 and 2009 plan years, respectively. 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, 2010, 9.1%, 10.8%, 10.1% and 9.7%, 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 5.75%; 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.

Pension Plan Assets

Percentage of fair value of Pension Plan assets at December 31:

	2010	2009
Equity	68%	72 %
Fixed income	29	25
Cash	3	3
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 n 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 chmark 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 Pension Plan may invest, including prohibitions on short sales.

Supplemental Non-qualified Defined Benefit Retirement Plans

We have various supplemental retirement plans ("Supplemental Plans") for key executives. The Supplemental Plans are non-qualified defined benefit plans. We use a December 31 measurement date for the Supplemental 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 plan. We also amended the Non-qualified Deferred Compensation Plan (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.

Supplemental Plan Assets

The Supplemental Plans have no assets. We fund on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Plan

Employees who are participants in our Non-Pension Postretirement Healthcare Plan ("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 Healthcare Plan periodically. We are not pre-funding our retiree medical plan. We use a December 31 measurement date for the Healthcare Plan. In July 2009, the Board of Directors approved an amendment to the Healthcare Plan which changed the structure of the Healthcare Plan for non-union employees to a Retiree Medical Savings Account (RMSA) structure. This change was effective January 1, 2010. In September 2010, the bargaining unit employees voted to change the structure of their benefits to an RMSA. This change is effective January 1, 2011. It has been determined that the Healthcare Plan's post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy.

Plan Assets

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

Plan Contributions and Estimated Cash Flows

Contributions made to the Supplemental Non-qualified Defined Benefit Retirement Plans and the Non-pension Defined Benefit Postretirement Plan are expected to be made in the form of benefit payments. Contributions to each of the plans were as follows (in thousands):

	2010	2009
Defined Benefit Plans		
Defined Benefit Pension Plan	$ 8,798	$ —
Non-pension Defined Benefit Postretirement Healthcare Plan	$ 657	$ 578
Supplemental Non-Qualified Defined Benefit Plan	$ 108	$ 89
Defined Contribution Plans		
Company Retirement Contribution	$ 171	$ —
Matching contributions	$ 1,029	$ 712

Contributions to our employee benefit plans to be made in 2011 are as follows (in thousands):

	2011
Defined Benefit Plans	
Defined Benefit Pension Plan	$ —
Non-Pension Defined Benefit Postretirement Healthcare Plan	$ 503
Supplemental Non-Qualified Defined Benefit Plan	$ 108

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.

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

Defined Benefit Pension Plan	December 31, 2010			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total Fair Value
Registered Investment Companies	$ 28,042	$ —	$ —	$ 28,042
Common Collective Trust	—	19,104	—	19,104
Insurance contracts	—	1,082	—	1,082
Total investments measured at fair value	$ 28,042	$ 20,186	$ —	$ 48,228

Defined Benefit Pension Plan	December 31, 2009			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total Fair Value
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

Plan Reconciliations

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

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2010	2009	2010	2009	2010	2009
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 55,615	$ 51,965	$ 1,690	$ 1,672	$ 9,432	$ 7,393
Service cost	1,215	1,155	—	—	340	216
Interest cost	3,280	3,143	100	100	547	444
Actuarial loss (gain)	4,129	1,686	54	7	(88)	3,474
Amendments	260	100	—	—	(2,270)	(1,960)
Discount rate change	—	1,047	—	—	—	—
Benefits paid	(2,472)	(2,312)	(109)	(89)	(658)	(579)
Asset transfer (to) from affiliate	(3,300)	(121)	417	—	(328)	(23)
Plan curtailment reduction	(974)	(1,048)	—	—	—	—
Medicare Part D adjustment	—	—	—	—	88	46
Plan participants' contributions	—	—	—	—	454	421
Net increase (decrease)	2,138	3,650	462	18	(1,915)	2,039
Projected benefit obligation at end of year	$ 57,753	$ 55,615	$ 2,152	$ 1,690	$ 7,517	$ 9,432

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	
	2010	2009	2010	2009	2010	2009
Beginning market value of plan assets	$ 39,040	$ 32,100	$ —	$ —	$ —	$ —
Investment income	5,361	9,337	—	—	—	—
Benefits paid	(2,472)	(2,312)	—	—	—	—
Employer contributions	8,798	—	—	—	—	—
Asset transfer to affiliate	(2,499)	(85)	—	—	—	—
Ending market value of plan assets	$ 48,228	$ 39,040	$ —	$ —	$ —	$ —

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	
	2010	2009	2010	2009	2010	2009
Regulatory asset (liability)	$ 18,049	$ 19,580	$ —	$ —	$ (1,050)	$ 1,443
Current (liability)	$ —	$ —	$ (141)	$ (98)	$ (428)	$ (325)
Non-current (liability)	$ (9,525)	$ (16,576)	$ (2,011)	$ (1,592)	$ (7,096)	$ (9,110)

Accumulated Benefit Obligation

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2010	2009	2010	2009	2010	2009
Accumulated benefit obligation	$ 52,250	$ 47,745	$ 2,058	$ 1,645	$ 7,517	$ 9,432

ponents of Net Periodic Expense

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Service cost	$ 1,214	$ 1,155	$ 1,117	$ —	$ —	$ —	$ 340	$ 216	$ 211
Interest cost	3,280	3,143	3,032	100	100	120	547	444	417
Expected return on assets	(3,008)	(2,780)	(4,374)	—	—	—	—	—	—
Amortization of prior service cost	62	87	112	—	—	1	(141)	—	—
Amortization of transition obligation	—	—	—	—	—	—	171	51	51
Recognized net actuarial loss (gain)	1,378	1,586	—	30	43	44	—	—	(1)
Curtailment expense	57	189	—	—	—	—	—	—	—
Net periodic expense	$ 2,983	$ 3,380	$ (113)	$ 130	$ 143	$ 165	$ 917	$ 711	$ 678

Accumulated Other Comprehensive Income (Loss)

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

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2010	2009	2010	2009	2010	2009
Net loss	$ —	$ —	$ (418)	$ (324)	$ —	$ —
Prior service cost	—	—	—	—	—	—
Transition obligation	—	—	—	—	—	—
	$ —	$ —	$ (418)	$ (324)	$ —	$ —

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 2011 were as follows (in thousands):

	Defined Benefits Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
Net loss	$ 966	$ 31	$ 106
Prior service cost	40	—	(204)
Transition obligation	—	—	—
Total net periodic benefit cost expected to be recognized during calendar year 2011	$ 1,006	$ 31	$ (98)

Assumptions

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Weighted-average assumptions used to determine benefit obligations:									
Discount rate	5.50%	6.05%	6.20%	5.50%	6.10%	6.20%	5.00%	5.90%	6.10%
Rate of increase in compensation levels	3.70%	4.25%	4.25%	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:									
Discount rate	6.05%	6.25%	6.35%	6.10%	6.20%	6.35%	5.90%	6.10%	6.35%
Expected long-term rate of return on assets*	8.00%	8.50%	8.50%	N/A	N/A	N/A	N/A	N/A	N/A
ate of increase in mpensation levels	4.25%	4.25%	4.34%	5.00%	5.00%	N/A	N/A	N/A	N/A

* The expected rate of return on plan assets changed to 7.75% for the calculation of the 2011 net periodic pension cost.

The healthcare benefit obligation was determined at December 31, 2010, using an initial healthcare trend rate of 9.5% grading down to an ultimate rate of 4.5% in 2027, and at December 31, 2009, using an initial healthcare trend rate of 10.0% trending down to an ultimate rate of 4.5% in 2027.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1% increase or 1% decrease in the healthcare cost trend assumptions would affect the service and interest costs and the accumulated periodic postretirement benefit obligation as follows (dollars in thousands):

	Service and Interest Costs		Accumulated Periodic Postretirement Benefit Obligation	
	Dollars	Percent	Dollars	Percent
1% increase	$ 147	17 %	$ 426	6 %
1% (decrease)	$ (114)	(13)%	$ (375)	(5)%

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
2011	$ 2,817	$ 141	$ 503	$ (75)	$ 428
2012	$ 2,907	$ 122	$ 600	$ (82)	$ 518
2013	$ 3,016	$ 102	$ 652	$ (87)	$ 565
2014	$ 3,148	$ 103	$ 699	$ (91)	$ 608
2015	$ 3,224	$ 91	$ 723	$ (95)	$ 628
2016-2020	$ 18,167	$ 583	$ 4,266	$ (500)	$ 3,766

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 or after-tax basis, up to a maximum amount established by the Internal Revenue Service. The plan provides for company matching contributions and company retirement contributions. Employer contributions vest at 20% per year and are fully vested when the participant has 5 years of service.

RELATED-PARTY TRANSACTIONS

Receivables and Payables

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

	2010	2009
Related party receivables	$ 6,891	$ 4,146
Related party payables	$ 12,562	$ 10,030

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.

Advances under this note bear interest at 2.75% above the daily LIBOR rate (3.01% at December 31, 2010). We had the following balances with the Utility Money Pool as of and for the years ended December 31 (in thousands):

	2010	2009	2008
Notes receivable (payable) with Utility Money Pool, net	$ 39,862	$ 57,737	$ (70,184)
Net interest revenue (expense)	$ 467	$ (1,123)	$ (865)

Other Balances and Transactions

We had the following related party transactions for the years ended December 31, 2010 and 2009 included in the corresponding captions in the accompanying Statements of Income:

- We received revenues from Black Hills Wyoming, Inc. for the transmission of electricity.
- We received revenues from Cheyenne Light for the sale of electricity and dispatch services.
- We recorded revenues relating to payments received pursuant to a natural gas swap entered into with Enserco.
- We purchase coal from WRDC. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.
- We purchase excess power generated by Cheyenne Light.
- In order to fuel our combustion turbine, we purchase natural gas from Enserco. 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 costs incurred on our behalf.
- We have two contracts with Cheyenne Light under which Cheyenne Light sells up to 40 MW of wind-generated, renewable energy to us.

	2010	2009	2008
	(in thousands)		
Revenues:			
Black Hills Wyoming for transmission of electricity	$ 1,378	$ 873	$ 1,245
Cheyenne Light for electricity and dispatch services	$ 1,200	$ 1,823	$ 2,778
Natural gas swaps from Enserco	$ —	$ —	$ 200
Purchases:			
Coal purchases from WRDC	$ 13,569	$ 16,284	$ 15,469
Excess power purchased from Cheyenne Light	$ 8,664	$ 8,580	$ 6,387
Natural gas from Enserco	$ 1,652	$ 2,250	$ 8,049
Corporate support services from Parent	$ 17,145	$ 15,014	$ 12,391
Renewable wind energy from Cheyenne Light	$ 4,538	$ 2,791	$ 628

We have funds on deposit from Black Hills Wyoming for transmission system reserve which are included in Other, non-current liabilities on the accompanying Balance Sheets. We have transmission system reserve balances as follows as of December 31 (in thousands):

	2010	2009
Deferred credits and other liabilities	$ 2,044	$ 1,978

Interest on the transmission system reserve deposit accrues quarterly at an average prime rate (3.25% at December 31, 2010). We paid interest for the years ended December 31 as follows (in thousands):

	2010	2009	2008
Interest expense	$ 65	$ 70	$ 114

(12) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2010	2009	2008
	(in thousands)		
Non-cash investing activities -			
Property, plant and equipment financed with accrued liabilities	$ 7,188	$ 10,191	$ 13,294
Money pool activity - net repayment of funds loaned	$ —	$ 25,000	$ —
Non-cash financing activities -			
Money pool activity - net repayment of funds borrowed	$ —	$ (25,000)	$ —
Supplemental disclosure of cash flow information:			
Cash (paid) refunded during the period for -			
Interest (net of amounts capitalized)	$ (19,554)	$ (14,252)	$ (11,578)
Income taxes	$ 15,805	$ 3,700	$ 5,877

(13) COMMITMENTS AND CONTINGENCIES

Partial Sale of Wygen III

On April 9, 2009, we sold to MDU a 25% ownership interest in our Wygen III generation facility. 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 continued to reimburse us for its 25% of the total costs paid to complete the project. The Wygen III generation facility began commercial operations on April 1, 2010. In conjunction with the sales transaction, we also modified a 2004 PPA between us and MDU.

On July 14, 2010, we sold a 23% ownership interest in Wygen III to the City of Gillette for $62.0 million. The purchase terminates the current PPA with the City of Gillette, and the Wygen III Participation Agreement has been amended to include the City of Gillette. The Participation Agreement provides that the City of Gillette will pay us for administrative services and share in the costs of operating the plant for the life of the facility. The estimated amount of net fixed assets sold totaled $55.8 million. We recognized a gain on the sale of $6.2 million.

Power Purchase and Transmission Services Agreements

We have the following power purchase and transmission agreements as of December 31, 2010:

- 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;
- 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;
- Cheyenne Light entered into a 20-year PPA with Happy Jack for 29.4 MW of energy. Under a separate inter-company agreement expiring in 2028, Cheyenne Light has agreed to sell 50% of the facility output from Happy Jack to us;
- Cheyenne Light entered into a 20-year PPA with Silver Sage for 30 MW of energy. Under a separate inter-company agreement expiring in 2029, 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.

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

Contract	Contract Type	Expiring	2010	2009	2008
PacifiCorp	Electric capacity and energy	2023	$ 12,936	$ 11,862	$ 11,571
PacifiCorp	Transmission access	2023	$ 1,215	$ 1,215	$ 1,215
Cheyenne Light	Happy Jack Wind Farm	2028	$ 2,815	$ 2,078	$ 628
Cheyenne Light	Silver Sage Wind Farm	2029	$ 1,723	$ 713	$ —

Long-Term Power Sales Agreements

We have the following power sales agreements as of December 31, 2010:

- In March 2010, we entered into a seven-year PPA and Purchase Option Agreement with the City of Gillette effective April 2010 that replaces a previous agreement. This PPA provided the City of Gillette, with an option to purchase a 23% ownership interest in our Wygen III facility which commenced commercial operations on April 1, 2010. The City of Gillette exercised its option to purchase the 23% ownership interest in Wygen III and the transaction closed in July 2010. The PPA terminated upon the closing of the transaction. We retain responsibility for operations of the facility with a life-of-plant lease and agreement for operations and coal supply. We entered into a five year agreement with the City of Gillette to dispatch the City of Gillette's first 23% of net generating capacity. MWs from the Wygen III unit are deemed to supply a portion of the City of Gillette's capacity and energy annually. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23% from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, we will also provide the City of Gillette their operating component of spinning reserves;

- An agreement with MDU to provide 25% of Wygen III's net generating capacity for the life of the plant. In conjunction with MDU's April 2009 purchase of 25% ownership interest in Wygen III, an agreement to supply 74 MW of capacity and energy through 2016 was modified. The sales to MDU have been integrated into our control area and are considered part of our firm native load. MWs from the Wygen III unit are deemed to supply a portion of the required 74 MW. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, MDU will be provided with its 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU;

- 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 commenced on April 1, 2010. Under this contract, MEAN purchases 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.

(14) QUARTERLY HISTORICAL DATA (Unaudited)

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2010				
Operating revenues	$ 54,489	$ 56,438	$ 59,051	$ 59,785
Operating income	$ 9,361	$ 10,510	$ 21,092	$ 14,305
Net income	$ 5,934	$ 4,102	$ 14,078	$ 7,154
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

Company Name: Black Hills Power, Inc.

BALANCE SHEET

Year: 2010

	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		986,005	-100%
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		3,748	-100%
12		**TOTAL Other Noncurrent Liabilities**		989,753	-100%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	21,855,401	13,521,848	62%
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies	10,030,043	12,558,267	-20%
20	235	Customer Deposits	669,906	977,967	-32%
21	236	Taxes Accrued	4,380,204	3,973,829	10%
22	237	Interest Accrued	5,449,671	4,126,079	32%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	2,319,164	1,264,725	83%
27	242	Miscellaneous Current & Accrued Liabilities	6,416,568	4,863,936	32%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	51,120,957	41,286,651	24%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	4,224,858	3,434,637	23%
34	253	Other Deferred Credits	38,262,655	38,611,351	-1%
35	255	Accumulated Deferred Investment Tax Credits	113,590	14,266	696%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	112,904,920	152,444,747	-26%
39		**TOTAL Deferred Credits**	155,506,023	194,505,001	-20%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		813,894,194	822,701,759	-1%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2010

	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: 2010

	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	413,196	-6%
39	365	Overhead Conductors & Devices	427,905	438,481	-2%
40	366	Underground Conduit	909	909	
41	367	Underground Conductors & Devices	15,834	15,834	
42	368	Line Transformers	46,941	48,686	-4%
43	369	Services	3,367	6,344	-47%
44	370	Meters	13,258	434	2955%
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49		**TOTAL Distribution Plant**	1,374,831	1,401,740	-2%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2010

	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		2,935	-100%
10	395	Laboratory Equipment			
11	396	Power Operated Equipment			
12	397	Communication Equipment	14,732	15,157	-3%
13	398	Miscellaneous Equipment			
14	399	Other Tangible Property			
15					
16	**TOTAL General Plant**		14,732	18,092	
17					
18	**TOTAL Electric Plant in Service**		1,389,563	1,419,832	-2%

MONTANA DEPRECIATION SUMMARY

Year: 2010

	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	1,401,740	912,201	926,971	
8	General	18,092	10,597	11,230	
9	**TOTAL**	1,419,832	922,798	938,201	

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

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

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	83.4.25			
2	Order Number	4998			
3					
4	Common Equity		52.83%	15.00%	7.92%
5	Preferred Stock		11.96%	9.03%	1.08%
6	Long Term Debt		35.21%	7.75%	2.73%
7	Other				
8	**TOTAL**		100.00%		11.73%
9					
10	Actual at Year End				
11					
12	Common Equity		52.81%		
13	Preferred Stock				
14	Long Term Debt		47.19%		
15	Other				
16	**TOTAL**		100.00%		

Company Name: Black Hills Power, Inc. **SCHEDULE 23**

STATEMENT OF CASH FLOWS

Year: 2010

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	23,138,854	31,267,992	-26%
6	Depreciation	19,313,360	22,029,623	-12%
7	Amortization	461,368	(6,541,711)	107%
8	Deferred Income Taxes - Net	11,724,815	25,625,579	-54%
9	Investment Tax Credit Adjustments - Net	(124,398)		100%
10	Change in Operating Receivables - Net	13,301,001	(14,542,283)	191%
11	Change in Materials, Supplies & Inventories - Net	484,106		-100%
12	Change in Operating Payables & Accrued Liabilities - Net	(13,776,381)	(5,523,373)	-149%
13	Allowance for Funds Used During Construction (AFUDC)	(5,831,355)	(2,748,351)	-112%
14	Change in Other Assets & Liabilities - Net	(10,072,860)	1,035,009	-1073%
15	Other Operating Activities (explained on attached page)			
16	**Net Cash Provided by/(Used in) Operating Activities**	38,618,510	50,602,485	-24%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(82,645,360)	(78,601,707)	-5%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets		62,000,000	-100%
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates	(127,967,110)	17,875,221	-816%
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained below *)	(4,161,377)	2,202,407	-289%
27	**Net Cash Provided by/(Used in) Investing Activities**	(214,773,847)	3,475,921	-6279%
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	(2,016,387)	(52,566,198)	96%
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 **)	(123,511)	(1,176,314)	90%
46	**Net Cash Provided by (Used in) Financing Activities**	177,860,102	(53,742,512)	431%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	1,704,765	335,894	408%
49	**Cash and Cash Equivalents at Beginning of Year**	4,175	1,708,940	-100%
50	**Cash and Cash Equivalents at End of Year**	1,708,940	2,044,834	-16%

*Primarily changes in non-trade receivables
**Payment of deferred financing costs

LONG TERM DEBT

Year: 2010

	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	03/2010	6,000,000	5,906,578		9.49%	70,405	
2									
3	Series Z	05/1991	06/2010	35,000,000	34,790,305		9.35%	787,901	
4									
5	Series AC	02/1995	02/2010	30,000,000	29,812,500		8.06%	201,500	
6									
7	Series AE	08/2002	08/2032	75,000,000	74,343,750	75,000,000	7.23%	5,422,500	7.23%
8									
9	Series AF	10/09	11/39	180,000,000	177,975,846	180,000,000	6.125%	10,994,375	6.11%
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%	74,400	4.80%
13	Campbell Cty 5.35%	11/2004	10/2024	12,200,000	12,062,750	12,200,000	5.35%	652,700	5.35%
14	Pennington Cty 4.8%	11/2004	10/2014	2,050,000	2,026,938	2,050,000	4.80%	98,400	4.80%
15	Weston Cty 4.8%	11/2004	10/2014	2,850,000	2,817,938	2,850,000	4.80%	136,800	4.80%
16									
17	1994 A Environ Improv Bond	06/1994	06/2024	3,000,000	2,930,057	2,855,000	8.00%	174,155	6.10%
18									
19	Bear Paw Energy	06/2000	05/2012	1,078,000	1,078,000	117,173	13.66%	21,575	18.41%
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			348,728,000	345,277,225	276,622,173		18,634,711	6.74%

Company Name: Black Hills Power, Inc. **SCHEDULE 25**

PREFERRED STOCK

Year: 2010

	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										
15										
16										
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19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2010

		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: 2010

	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: 2010

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	1,420
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	(938)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	482
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	2,492
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	2,492
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	2,492
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	13
36		Commercial	21
37		Industrial	2
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	36
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	92,584
45		Average Annual Residential Cost per (Kwh) (Cents) *	8.00
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	586
48		Gross Plant per Customer	13.39

MONTANA CUSTOMER INFORMATION

Year: 2010

	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						
10						
11						
12						
13						
14						
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18						
19						
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21						
22						
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24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**					

Company Name: Black Hills Power, Inc. **SCHEDULE 30**

MONTANA EMPLOYEE COUNTS

Year: 2010

	Department	Year Beginning	Year End	Average
1	N/A			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
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36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**			

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

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2011

	Project Description	Total Company	Total Montana
1	N/A		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
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42			
43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**		

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2010

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	6	1900	376	292,804	87,069
2	Feb.	9	800	365	241,933	53,181
3	Mar.	10	1900	321	320,565	133,733
4	Apr.	6	1700	297	284,465	127,501
5	May	28	1600	309	293,601	142,219
6	Jun.	30	1400	375	259,084	99,359
7	Jul.	26	1700	396	282,883	89,234
8	Aug.	11	1600	384	290,412	97,288
9	Sep.	9	1400	318	278,409	122,775
10	Oct.	5	1600	302	290,286	154,772
11	Nov.	22	1800	363	283,147	129,122
12	Dec.	31	1800	377	288,053	116,092
13	**TOTAL**				3,405,642	1,352,345

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	1,987,037	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,655,089
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	19,269	for Resale	265,857
7	(Less) Energy for Pumping			
8	**NET Generation**	2,006,306	Non-Requirements Sales	
9	Purchases	1,440,579	for Resale	1,395,135
10	Power Exchanges			
11	Received	57,896	Energy Furnished	
12	Delivered	(32,149)	Without Charge	
13	**NET Exchanges**	25,747		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	7,216,756	Electric Utility	134,632
16	Delivered	(7,216,756)		
17	**NET Transmission Wheeling**	-	Total Energy Losses	-
18	Transmission by Others Losses	(21,925)		
19	**TOTAL**	3,450,707	**TOTAL**	3,450,713

SOURCES OF ELECTRIC SUPPLY

Year: 2010

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	1,564
2					
3	Thermal	Ben French	Rapid City, SD	10	(255)
4					
5	Thermal	Ben French	Rapid City, SD	24	131,054
6					
7	Thermal	Osage	Osage, WY	35	134,137
8					
9	Thermal	Wyodak	Gillette, WY	69	517,627
10					
11	Thermal	Neil Simpson I	Gillette, WY	20	152,891
12					
13	Thermal	Neil Simpson II	Gillette, WY	84	689,880
14					
15	Thermal	Lange	Rapid City, SD	39	4,733
16					
17	Thermal	Neil Simpson CT 1	Gillette, WY	39	13,780
18					
19	Thermal	Wygen III	Gillette, WY	100	409,706
20					
21	Purchases	See Schedule 32			1,440,579
22					
23	Wheeling	See Schedule 32			-
24					
25	Total Interchange	See Schedule 32			25,747
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**			518	3521443

Company Name: Black Hills Power, Inc. **SCHEDULE 35**

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2010

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

Company Name: 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					

Company Name: Black Hills Power, Inc. **SCHEDULE 36**

MONTANA CONSUMPTION AND REVENUES

Year: 2010

	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	$7,600	$7,100	94	89	13	13
2	Commercial - Small	55,800	72,900	595	914	21	21
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	2,428,900	2,237,400	48,953	46,501	2	2
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**	$2,492,300	$2,317,400	49,642.0	47,504.0	36	36