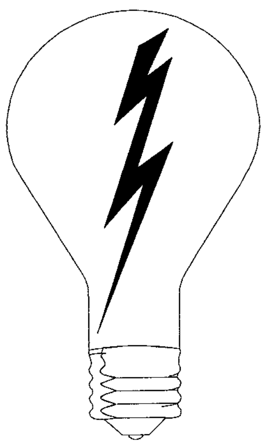
YEAR ENDING ________ 2007

ANNUAL REPORT
OF

BLACK HILLS POWER

ELECTRIC UTILITY



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

2007 Electric Annual Report

Instructions

General

1. A Microsoft EXCEL© workbook of the annual report is provided on our website for your convenience. The workbook contains the schedules of the annual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1". By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell. You may also obtain these instructions and the report in both an Adobe Acrobat© format and as an EXCEL© file from our website at **http://psc.mt.gov/**. Please be sure you use the 2006 report form.

2. Use of the EXCEL© workbook is optional.

3. All forms must be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report must be filed. **Please submit one unbound copy of the annual report along with the regular number of annual reports that you submit.** This aids in scanning the report so that it may be published on our web site. The orientation and margins are set up on each individual worksheet and should print on one page.

4. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

5. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

6. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

7. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

8. All companies owned by another company shall attach a corporate structure chart of the holding company.

9. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

10. The following schedules shall be filled out with information on a total company basis:

    Schedules 1 through 5
    Schedules 6 and 7
    Schedule 14
    Schedule 17 and 18
    Schedules 23 through 26
    Schedules 33 and 34

11. All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

12. Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

13. FERC Form-1 sheets may not be substituted in lieu of completing annual report schedule.

14. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 101 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

Schedule 12

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form using FASB 87 and 132 guidelines.

3. Interest rate percentages shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 15 and 16. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 15 and 16. All assumptions used in quantifying cost containment results shall be disclosed.

2. Schedule 15 shall be filled out using FASB 106 and 132 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

3. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 31

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 32

1. Provide a written narrative detailing the sources and amounts of electric supply at the time of the annual peak.

Schedule 34

1. The following categories shall be used in the Type column: Thermal, Hydro, Nuclear, Solar, Wind, GeoThermal, Qualifying Facility (QF), Independent Power Producer (IPP), Off System Purchases, or Other. Spot market purchases shall be separately identified. Entries for the Other category shall be listed as separate line items and include a description.
   Note: For Off System Purchases, the Utility/Company whom the purchases are being made from shall be entered in the Plant Name column, the termination date of the purchased power contract shall be entered in the Location column.

2. Provide a written narrative of all outages exceeding one hour which occurred during the year. Explain the reason for the outage. If routine maintenance schedules are exceeded, explain the reason.

Schedule 35

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

Schedule 35a

1. Contracted or committed current year expenditures include those expenditures that derive from preexisting contracts or commitments related to current year program activity but which will actually occur in a year other than the current year.

2. Expected average annual bill savings from weatherization should reflect average household bill savings based on the total households weatherized and the combined savings of all weatherization measures installed.

Electric Annual Report

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Description	Schedule

IDENTIFICATION

Year: **2007**

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:	David R Emery 625 Ninth Street Rapid City, SD 57701
5.	Person Responsible for This Report:	Mark T. Thies Exec. VP & CFO
5a.	Telephone Number:	605-721-1700

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	74,125
3	John R. Howard	Rapid City, SD	73,250
4	Kay S. Jorgensen	Spearfish, SD	75,500
5	David C. Ebertz	Gillette, WY	64,750
6	Gary L Pechota	Bethlehem, PA	39,750
7	Stephen D. Newlin	Medina, MN	61,625
8	Jack W. Eugster	Excelsior, MN	67,375
9	Warren L Robinson	Anthem, AZ	48,250
10	John B. Vering	Southlake, TX	66,625
11			
12	(a) Officer of the Company and not compensated as a Director		
13			
14			
15			
16			
17			
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19			
20			

Officers

Year: 2007

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman & Chief Executive Officer/Interim CFO		David R. Emery
2	President & Chief Operating Officer		Linden R. Evans
3	Interim CFO Chief Financial Officer		Perry S. Krush
4	Senior Vice President - General Counsel		Steven J. Helmers
5	Senior Vice President - Corporate Administration		James M. Mattern
6	Senior Vice President - Strategic Planning & Development		Maurice T. Klefeker
7	Vice President - Operations		Stuart A. Wevik
8	Vice President - Power Delivery		Mark L. Lux
9	Vice President - Governance & Corporate Secretary		Roxann R. Basham
10	Vice President & Corporate Controller		Perry S. Krush
11	Vice President, Treasurer & Chief Risk Officer		Garner M. Anderson
12	Vice President - Corporate Affairs		Kyle D. White
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CORPORATE STRUCTURE

Year: 2007

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	24,895,901	100.00%
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41				
42				100.00%
43				
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49				
50	**TOTAL**		24,895,901	

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

SCHEDULE 5

CORPORATE ALLOCATIONS

Year: 2007

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Not significant to Montana Operations					
2						
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34	**TOTAL**					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2007

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	Coal sales to Utility	Fair Market Value (based on similar	12,635,001	29.74%	174,363
2	Development Corp.		arms-length transactions)			
3						
4	Enserco Energy, Inc.	Gas sales to Utility	Fair Market Value (based on similar	4,535,416	0.12%	62,589
5			arms-length transactions)			
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32	**TOTAL**			17,170,417		236,952

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

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					
2	Development Corp	Electricity	Wyoming Industrial Rate	749,970	100.00%	
3						
4	Black Hills Wyoming	Transmission Service	Point-to-Point			
5			Open Access Transmission Tariff	488,753	100.00%	
6						
7	Black Hills Wyoming	Non-firm energy sales	Fair Market Value (Based on	1,143,817	100.00%	
8			similar arms-length transactions)			
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32	**TOTAL**			2,382,540		

MONTANA UTILITY INCOME STATEMENT

Year: 2007

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	192,821,750	199,440,689	3.43%
2					
3		Operating Expenses			
4	401	Operation Expenses	116,477,995	115,701,592	-0.67%
5	402	Maintenance Expense	9,134,698	8,991,643	-1.57%
6	403	Depreciation Expense	19,649,905	20,611,646	4.89%
7	404-405	Amortization of Electric Plant			
8	406	Amort. of Plant Acquisition Adjustments	151,404	151,404	
9	407	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	6,999,062	6,248,208	-10.73%
12	409.1	Income Taxes - Federal	12,928,458	8,685,058	-32.82%
13		- Other			
14	410.1	Provision for Deferred Income Taxes	4,119,214	5,182,994	25.82%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(6,685,678)	(1,085,400)	83.77%
16	411.4	Investment Tax Credit Adjustments	(233,329)	(233,329)	
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**	162,541,729	164,253,816	1.05%
21		**NET UTILITY OPERATING INCOME**	30,280,021	35,186,873	16.20%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	6,344	7,013	10.55%
3	442	Commercial & Industrial - Small	27,588	70,462	155.41%
4		Commercial & Industrial - Large	1,015,175	1,474,385	45.23%
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**	1,049,107	1,551,861	47.92%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	1,049,107	1,551,861	47.92%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	1,049,107	1,551,861	47.92%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	(516)	(69)	86.71%
19	451	Miscellaneous Service Revenues			
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**	(516)	(69)	86.71%
26		**Total Electric Operating Revenues**	1,048,591	1,551,792	47.99%

BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc. (the Company) is an electric utility serving customers in South Dakota, Wyoming and Montana. The Company is a wholly owned subsidiary of BHC or the Parent, a public registrant listed on the New York Stock Exchange.

Basis of Presentation

The financial statements include the accounts of Black Hills Power, Inc. and also the Company's ownership interests in the assets, liabilities and expenses of its jointly owned facilities.

Basis of Accounting

The financial statements have been prepared in accordance with the accounting requirements of the Uniform System of Accounts prescribed by the FERC. The principle differences from generally accepted accounting principles include the exclusion of current maturities of long term debt from current liabilities, the requirement to report deferred tax assets and liabilities separately, rather than as a single amount, and the recording of asset removal costs as accumulated depreciation rather than as a liability.

Rate Regulation

Rates for our retail electric service are subject to regulation by the SDPUC for customers in South Dakota, the WPSC for customers in Wyoming and the MTPSC for customers in Montana. Any changes in retail rates are subject to approval by the respective regulatory body. We have rate adjustment mechanisms in Montana and South Dakota which provide for pass-through of certain costs related to the purchase, production and/or transmission of electricity. We are also subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) with respect to accounting practices and wholesale electricity sales. We have been granted market-based rate authority by the FERC and are not required to file cost-based tariffs for wholesale electric rates. Rates charged by us for use of our transmission system are subject to regulation by the FERC.

Environmental Regulations

We are subject to federal, state and local laws and regulations with regard to air and water quality, waste disposal, federal health and safety regulations, and other environmental matters. We have incurred, and expect to incur, capital, operating and maintenance costs to comply with the operations of our plants. While the requirements are evolving, it is virtually certain that environmental requirements placed on the operations will continue to be more restrictive.

Regulatory Accounting

The Company's 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.

The Company's regulated utility operations follow the provisions of SFAS 71 and its financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating its electric operations. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply to the Company's regulated generation operations. In the event the Company determines that it no longer meets the criteria for following SFAS 71, the accounting impact to the Company could be an extraordinary non-cash charge to operations of an amount that could be material.

On December 31, 2007 and 2006, the Company had the following regulatory assets and liabilities:

	2007	2006
Regulatory assets:		
Unamortized loss on reacquired debt	$ 2,527	$ 2,694
AFUDC	4,139	3,926
Defined benefit postretirement plans	2,998	10,778
Deferred energy costs	939	—
Other	235	290
	$ 10,838	$ 17,688
Regulatory liabilities:		
Deferred income taxes	$ 2,094	$ 2,414
Cost of removal for utility plant	8,510	5,361
Other	760	—
	$ 11,364	$ 7,775

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

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to allowance for uncollectible accounts receivable, long-lived asset values and useful lives, employee benefits plans and contingency accruals. Actual results could differ from those estimates.

Utility Plant

Utility Plant is recorded at cost, which includes an allowance for funds used during construction (AFUDC) where applicable. The cost of utility plant retired, together with removal cost less salvage, is charged to accumulated depreciation. Repairs and maintenance of utility plant are charged to operations as incurred.

Depreciation provisions for regulated electric property, plant and equipment is computed on a straight-line basis using an annual composite rate of 3.1 percent in 2007 and 3.0 percent in 2006.

Allowance for Funds Used During Construction

AFUDC represents the approximate composite cost of borrowed funds and a return on capital used to finance a project. AFUDC for the years ended December 31, 2007 and 2006 was $0.9 million and $0.6 million, respectively. The equity component of AFUDC for 2007 and 2006 was $0.6 million and $0.4 million, respectively. The borrowed funds component of AFUDC for 2007 and 2006 was $0.3 million and $0.2 million, respectively. The equity component of AFUDC is included in Other income (expense), and the borrowed funds component of AFUDC is included in Interest expense on the accompanying Statements of Income.

Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are generally stated at cost on a weighted-average basis. To the extent fuel has been designated as the underlying hedged item in a "fair value" hedge transaction, those volumes are stated at market value using published industry quotations. As of December 31, 2007 and 2006, there were no market adjustments related to fuel.

Deferred Financing Costs

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

Derivatives and Hedging Activities

The Company, from time to time, utilizes risk management contracts including forward purchases and sales and fixed-for-float swaps to hedge the price of fuel for its combustion turbines, maximize the value of its natural gas storage or to fix the interest on its variable rate debt. Certain of the contracts qualify as derivatives under SFAS 133, which requires that every derivative instrument be recorded in the balance sheet as either an asset or liability, measured at its fair value. SFAS 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

SFAS 133 allows hedge accounting for qualifying fair value and cash flow hedges. SFAS 133 provides that the 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 be recognized currently in earnings in the same accounting period. SFAS 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income 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

The Company periodically evaluates whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining balance of its long-lived assets. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, the Company would estimate the future cash flows expected to result from the use of the assets and their eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) was less than the carrying amount of the long-lived assets, the Company would recognize an impairment loss. No impairment loss was recorded during 2007 or 2006.

Income Taxes

The Company uses 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. The Company classifies deferred tax assets and liabilities into current and non-current amounts based on the classification of the related assets and liabilities.

The Company files 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.

Fuel and Purchased Power Adjustment Tariffs

The Company's Montana Retail Tariffs contain clauses that allow recovery of certain fuel and purchased power costs in excess of the level of such costs included in base rates. These cost adjustment tariffs are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred. The adjustments are recognized as current assets or current liabilities until adjusted through future billing to customers. Sales to Montana account for less than 1 percent of the Company's total electric revenue.

In December 2006, we received an order from the SDPUC, effective January 1, 2007, approving a 7.8 percent increase in retail rates and the addition of tariff provisions for automatic cost adjustments. The cost adjustments require us to absorb a portion of power cost increases partially depending on earnings from certain short-term wholesale sales of electricity. Absent certain conditions, the order also restricts us from requesting an increase in base rates that would go into effect prior to January 1, 2010. Our previous rate structure, in place since 1995, did not contain fuel or purchased power adjustment clauses and only provided the ability to request rate relief from energy costs in certain defined situations. South Dakota retail customers account for approximately 90 percent of our total retail revenues.

The Company's Wyoming, Wholesale to Montana-Dakota Utilities Co., (a division of MDU Resources Group, Inc. (MDU)) and City of Gillette tariffs do not include an automatic fuel and purchased power adjustment tariff.

Recently Adopted Accounting Pronouncements

FIN 48

During June 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109 and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Adoption of FIN 48 did not have an effect on the Company's financial position, results of operations or cash flows.

SAB No. 108

During September 2006, the staff of the SEC released SAB No. 108, which provides guidance on how the effects of the carryover or reversal of prior year financial statement misstatements should be considered in quantifying a current year misstatement. Prior practice allowed the evaluation of materiality on the basis of (1) the error quantified as the amount by which the current year income statement was misstated (rollover method) or (2) the cumulative error quantified as the cumulative amount by which the current year balance sheet was misstated (iron curtain method). Reliance on either method in prior years could have resulted in misstatement of the financial statements. The guidance provided in SAB No. 108 requires both methods to be used in evaluating materiality. Immaterial prior year errors may be corrected with the first filing of prior year financial statements after adoption. The cumulative effect of the correction can either be reported in the carrying amounts of assets and liabilities as of the beginning of that fiscal year, and the offsetting adjustment made to the opening balance of retained earnings for that year, or by restating prior periods. Disclosure requirements include the nature and amount of each individual error being corrected in the cumulative adjustment, as well as a disclosure of when and how each error being corrected arose and the fact that the errors had previously been considered immaterial. SAB No. 108 is effective January 1, 2007. SAB No. 108 did not have an effect on the Company's financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

SFAS 157

During September 2006, the FASB issued SFAS 157, which applies under other accounting pronouncements that require or permit fair value measurements. This Statement defines fair value in accordance with GAAP and expands disclosures about fair value measurements. The Company is subject to the provisions of SFAS 157 beginning January 1, 2008. Management is currently evaluating the impact SFAS 157 will have on the Company's financial statements.

SFAS 158

During September 2006, the FASB issued SFAS 158. This Statement requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of financial position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position, and provides for related disclosures. The Company applied the recognition provisions of SFAS 158 as of December 31, 2006. Effective for fiscal years ending after December 15, 2008, SFAS 158 will require the measurement of the funded status of the plan to coincide with the date of the year-end statement of financial position. The funded status of the Company's pension and other postretirement benefit plans are currently measured as of September 30, 2007 (see Note 9).

SFAS 159

In February 2007, the FASB issued SFAS 159, which establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007. Management does not believe SFAS 159 will have a material adverse impact on the Company's financial statements.

Supplemental Disclosure of Cash Flow Information

Cash paid during the year 2007 and 2006 for interest was $11.8 million and $13.8 million, respectively and cash paid during the year 2007 and 2006 for income tax was $17.3 million and $6.8 million, respectively.

JOINTLY OWNED FACILITIES

The Company uses the proportionate consolidation method to account for its percentage interest in the assets, liabilities and expenses of the following facilities:

- The Company owns a 20 percent interest and PacifiCorp owns an 80 percent interest in the Wyodak Plant (Plant), a 362 MW coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp is the operator of the Plant. The Company receives 20 percent of the Plant's capacity and is committed to pay 20 percent of its additions, replacements and operating and maintenance expenses. As of December 31, 2007 and 2006, the Company's investment in the Plant included $80.4 million and $76.3 million, respectively, in electric plant and $43.5 million and $41.0 million, respectively, in accumulated depreciation, and is included in the corresponding captions in the accompanying Balance Sheets. The Company's share of direct expenses of the Plant was $7.3 million and $7.9 million for the years ended December 31, 2007 and 2006, respectively, and is included in the corresponding categories of operating expenses in the accompanying Statements of Income.

- The Company also owns a 35 percent interest and Basin Electric owns a 65 percent 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. The Company is committed to pay 35 percent of the additions, replacements and operating and maintenance expenses. The Company's share of direct expenses was $0.1 million and $0.1 million for the years ended December 31, 2007 and 2006, respectively. As of December 31, 2007 and 2006, the Company's investment in the transmission tie was $19.8 million, with $2.0 million and $1.5 million, respectively, of accumulated depreciation and is included in the corresponding captions in the accompanying Balance Sheets.

RISK MANAGEMENT

The Company holds natural gas in storage for use as fuel for generating electricity with its gas-fired combustion turbines. To minimize associated price risk and seasonal storage level requirements, the Company utilizes various derivative instruments in managing these risks. On December 31, 2007 and December 31, 2006, the Company had the following derivatives and related balances (in thousands):

	Notional*	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive Income/(Loss)
December 31, 2007							
Natural gas swaps	610,000	0.33	$ 238	$ —	$ 68	$ —	$ 170
December 31, 2006							
Natural gas swaps	310,000	0.25	$ 878	$ —	$ —	$ —	$ 878

*gas in MMbtus

Based on December 31, 2007 market prices, a $0.2 million gain would be realized and reported in pre-tax earnings during the next twelve months related to derivatives designated as a cash flow hedge. These estimated realized gains for the next twelve months were calculated using December 31, 2007 market prices. Estimated and actual realized gains will likely change during the next twelve months as market prices change.

LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	2007	2006
	(in thousands)	
First mortgage bonds:		
8.06% due 2010	$ 30,000	$ 30,000
9.49% due 2018	3,100	3,390
9.35% due 2021	23,310	24,975
7.23% due 2032	75,000	75,000
	131,410	133,365
Other long-term debt:		
Pollution control revenue bonds at 4.8% due 2014	6,450	6,450
Pollution control revenue bonds at 5.35% due 2024	12,200	12,200
Other	3,158	3,204
	21,808	21,854
Total long-term debt	153,218	155,219
Less current maturities	(2,009)	(2,002)
Net long-term debt	$ 151,209	$ 153,217

Substantially all of the Company's property is subject to the lien of the indenture securing its first mortgage bonds. First mortgage bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Scheduled maturities are approximately $2.0 million a year for the years 2008 and 2009, $32.0 million in 2010, $2.0 million a year for the years 2011 and 2012, and $113.2 million thereafter.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of the Company's financial instruments at December 31 are as follows (in thousands):

	2007				2006			
	Carrying Amount		Fair Value		Carrying Amount		Fair Value	
Cash and cash equivalents	$	2,033	$	2,033	$	1,223	$	1,223
Derivative financial instruments – assets	$	238	$	238	$	878	$	878
Derivative financial instruments – liabilities	$	68	$	68	$	—	$	—
Long-term debt	$	153,218	$	168,042	$	155,219	$	177,217

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

Cash and Cash Equivalents

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

Derivative Financial Instruments

These instruments are carried at fair value. Descriptions of the instruments the Company uses are included in Note 4.

Long-Term Debt

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

INCOME TAXES

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

	2007	2006
Current	$ 8,704	$ 12,928
Deferred	3,864	(2,799)
	$ 12,568	$ 10,129

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

Years ended December 31,	2007	2006
Deferred tax assets, current:		
Asset valuation reserve	$ 136	$ 87
Employee benefits	399	361
	535	448
Deferred tax liabilities, current:		
Prepaid expenses	181	177
Items of other comprehensive income	290	307
Other	82	102
	553	586
Net deferred tax liability, current	$ 18	$ 138
Deferred tax assets, non-current:		
Plant related differences	$ 1,316	$ 1,204
Regulatory asset	4,533	965
Employee benefits	3,366	6,896
Items of other comprehensive income	226	265
Other	128	128
	9,569	9,458
Deferred tax liabilities, non-current:		
Accelerated depreciation and other plant related differences	68,250	63,457
AFUDC	2,690	2,551
Regulatory liability	5,222	1,374
Employee benefits	2,284	6,297
Deferred costs	—	102
Other	884	841
	79,330	74,622

Net deferred tax liability, non-current	$	69,761	$	65,164
Net deferred tax liability	$	69,779	$	65,302

The following table reconciles the change in the net deferred income tax liability from December 31, 2006, to December 31, 2007, to the deferred income tax expense (in thousands):

		2007
Increase in deferred income tax liability from the preceding table	$	4,477
Deferred taxes related to regulatory assets and liabilities		(799)
Deferred taxes associated with other comprehensive loss		186
Deferred income tax expense for the period	$	3,864

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

	2007	2006
Federal statutory rate	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(1.0)	(1.3)
Deferred tax adjustments primarily related to plant-related changes in estimate	—	—
IRS tax exam adjustment*	—	2.6
Other	(0.5)	(1.2)
	33.5%	35.1%

*As a result of a settlement of an Internal Revenue Service (IRS) exam.

COMPREHENSIVE INCOME

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

2007	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Pension liability adjustment	$ 115	$ (39)	$ 76
Reclassification adjustments of cash flow hedges settled and included in net income	424	(148)	276
Net change in fair value of derivatives designated as cash flow hedges	(1,069)	372	(697)
Comprehensive loss	$ (530)	$ 185	$ (345)

2006	Pre-tax Amount	Tax Expense	Net-of-tax Amount
Pension liability adjustment	$ 48	$ (17)	$ 31
Amortization of cash flow hedges settled and deferred in AOCI and reclassified into interest expense	64	(22)	42
Net change in fair value of derivatives designated as cash flow hedges	1,097	(384)	713
Comprehensive income	$ 1,209	$ (423)	$ 786

EMPLOYEE BENEFIT PLANS

SFAS 158

The application of SFAS 158 requires recognition of the funded status of postretirement benefit plans in the statement of financial position. The funded status for pension plans is measured as the difference between the projected benefit obligation and the fair value of plan assets. The funded status for all other benefit plans is measured as the difference between the accumulated benefit obligation and the fair value of plan assets. A liability is recorded for an amount by which the benefit obligation exceeds the fair value of plan assets or an asset is recorded for any amount by which the fair value of plan assets exceeds the benefit obligation.

Prior to the December 31, 2006 effective date of SFAS 158, liabilities recorded for postretirement benefit plans were reduced by any unrecognized net periodic benefit cost. Upon adoption of SFAS 158, the unrecognized net periodic benefit cost, previously recorded as an offset to the liability for benefit obligations, was reclassified within AOCI, net of tax. The Company applied the guidance under SFAS 71, and accordingly, the unrecognized net periodic benefit cost that would have been reclassified to AOCI was alternatively recorded as a regulatory asset or regulatory liability, net of tax.

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Defined Benefit Pension Plan

The Company has a noncontributory defined benefit pension plan (Plan) covering the employees of the Company who meet certain eligibility requirements. The benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. The Company's funding policy is in accordance with the federal government's funding requirements. The Plan's assets are held in trust and consist primarily of equity and fixed income investments. The Company uses a September 30 measurement date for the Plan.

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

The expected long-term rate of return for equity investments was 9.5 percent for the 2007 and 2006 plan years. For determining the expected long-term rate of return for equity assets, the Company reviewed interest rate trends and annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2007, 11.6 percent, 12.7 percent, 10.4 percent and 10.8 percent, respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on 10-year treasury bonds of 7.1 percent from 1962 to 2007, and adjusted for recent declines in interest rates. The expected long-term rate of return on cash investments was estimated to be 4.0 percent; expected cash returns were estimated to be 2.0 percent below long-term returns on intermediate-term bonds.

Plan Assets

Percentage of fair value of Plan assets at September 30:

	2007	2006
Domestic equity	50.3%	50.3%
Foreign equity	26.3	25.3
Fixed income	20.9	15.6
Cash	2.5	8.8
Total	100.0%	100.0%

The Plan's investment policy includes a target asset allocation as follows:

Asset Class	Target Allocation
US Stocks	50%
Foreign Stocks	25%
Fixed Income	25%
Cash	0%

The Plan's investment policy includes the investment objective that the achieved long-term rates of return meet or exceed the assumed actuarial rate. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity and fixed income assets. The policy provides that the Plan will maintain a passive core U.S. Stock portfolio based on a broad market index. Complementing this core will be investments in U.S. and foreign equities through actively managed mutual funds.

The policy contains certain prohibitions on transactions in separately managed portfolios in which the Plan may invest, including prohibitions on short sales and the use of options or futures contracts. With regards to pooled funds, the policy requires the evaluation of the appropriateness of such funds for managing Plan assets if a fund engages in such transactions. The Plan has historically not invested in funds engaging in such transactions.

Cash Flows

The Company made no contributions to the Plan in 2007 and does not anticipate any employer contributions to the Plan in 2008.

Supplemental Nonqualified Defined Benefit Retirement Plans

The Company has various supplemental retirement plans for key executives of the Company. The Plans are nonqualified defined benefit plans. The Company uses a September 30 measurement date for the Plans.

Plan Assets

The Plan has no assets. The Company funds on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contribution is expected to be $0.1 million in 2008. Contributions are expected to be made in the form of benefit payments.

Non-pension Defined Benefit Postretirement Plan

Employees who are participants in the Company's Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service to the Company are entitled to postretirement healthcare benefits. These benefits are subject to premiums, deductibles, co-payment provisions and other limitations. The Company may amend or change the Plan periodically. The Company is not pre-funding its retiree medical plan. The Company uses a September 30 measurement date for the Plan.

It has been determined that the Plan's post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy. The effect of the Medicare Part D subsidy on the accumulated postretirement benefit obligation for the fiscal year ending December 31, 2007, was an actuarial gain of approximately $0.9 million. The effect on 2008 net periodic postretirement benefit cost will be a decrease of approximately $0.1 million.

Plan Assets

The Plan has no assets. The Company funds on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contribution is expected to be $0.2 million in 2008. Contributions are expected to be made in the form of benefit payments.

The following tables provide a reconciliation of the Employee Benefit Plan's obligations and fair value of assets for 2007 and 2006, components of the net periodic expense for the years ended 2007 and 2006 and elements of regulatory assets and liabilities and AOCI for 2007 and 2006.

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2007	2006	2007	2006	2007	2006
			(in thousands)			
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 50,340	$ 49,311	$ 1,999	$ 2,022	$ 6,791	$ 7,167
Service cost	1,137	1,085	—	—	211	249
Interest cost	2,923	2,720	116	113	398	398
Actuarial (gain) loss	(328)	156	(54)	(35)	(571)	(573)
Amendments	—	—	—	—	—	(205)
Discount rate change	(2,641)	—	—	—	—	—
Benefits paid	(2,145)	(2,095)	(103)	(101)	(638)	(526)
Asset transfer to affiliate	(349)	(837)	—	—	(19)	(135)
Medicare Part D adjustment	—	—	—	—	75	—
Plan participant's contributions	—	—	—	—	402	416
Net increase (decrease)	(1,403)	1,029	(41)	(23)	(142)	(376)
Projected benefit obligation at end of year	$ 48,937	$ 50,340	$ 1,958	$ 1,999	$ 6,649	$ 6,791

A reconciliation of the fair value of Plan assets (as of the September 30 measurement date) is as follows:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2007	2006	2007	2006	2007	2006
			(in thousands)			
Beginning market value of plan assets	$ 46,916	$ 43,859	$ —	$ —	$ —	$ —
Investment income	8,044	5,899	—	—	—	—
Benefits paid	(2,145)	(2,096)	—	—	—	—
Asset transfer to affiliate	(349)	(746)	—	—	—	—
Ending market value of plan assets	$ 52,466	$ 46,916	$ —	$ —	$ —	$ —

Amounts recognized in the statement of financial position consist of:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2007	2006	2007	2006	2007	2006
			(in thousands)			
Regulatory asset (liability)	$ 2,998	$ 10,637	$ —	$ —	$ (480)	$ 141
Current liability	—	—	129	630	186	198
Non-current asset (liability)	3,529	(3,423)	(1,801)	(1,343)	(6,399)	(6,486)

Accumulated Benefit Obligation

	Defined Benefit Pension Plans 2007	Defined Benefit Pension Plans 2006	Supplemental Nonqualified Defined Benefit Retirement Plans 2007	Supplemental Nonqualified Defined Benefit Retirement Plans 2006	Non-pension Defined Benefit Postretirement Plans 2007	Non-pension Defined Benefit Postretirement Plans 2006
	(in thousands)					
Accumulated benefit obligation	$ 41,823	$ 42,130	$ 1,808	$ 1,815	$ 6,649	$ 6,791

Components of Net Periodic Expense

	Defined Benefit Pension Plans 2007	Defined Benefit Pension Plans 2006	Supplemental Nonqualified Defined Benefit Retirement Plans 2007	Supplemental Nonqualified Defined Benefit Retirement Plans 2006	Non-pension Defined Benefit Postretirement Plans 2007	Non-pension Defined Benefit Postretirement Plans 2006
	(in thousands)					
ervice cost	$ 1,137	$ 1,085	$ —	$ —	$ 211	$ 249
nterest cost	2,923	2,720	116	113	398	398
xpected return on assets	(3,885)	(3,557)	—	—	—	—
mortization of prior service cost	103	103	1	1	—	(19)
mortization of transition obligation	—	—	—	—	51	117
ecognized net actuarial loss	408	665	57	67	—	—
et periodic expense	$ 686	$ 1,016	$ 174	$ 181	$ 660	$ 745

AOCI

In accordance with SFAS 158, amounts included in AOCI, after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31, are as follows:

	Defined Benefit Pension Plans 2007	Defined Benefit Pension Plans 2006	Supplemental Nonqualified Defined Benefit Retirement Plans 2007	Supplemental Nonqualified Defined Benefit Retirement Plans 2006	Non-pension Defined Benefit Postretirement Plans 2007	Non-pension Defined Benefit Postretirement Plans 2006
	(in thousands)					
Net loss	$ —	$ —	$ (418)	$ (491)	$ —	$ —
Prior service cost	—	—	(1)	(1)	—	—
Transition obligation	—	—	—	—	—	—
	$ —	$ —	$ (419)	$ (492)	$ —	$ —

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 2008 are as follows:

	Defined Benefits Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans (in thousands)	Non-pension Defined Benefit Postretirement Plans
Net loss	$ —	$ 32	$ 1
Prior service cost	73	—	—
Transition obligation	—	—	33
Total net periodic benefit cost expected to be recognized during calendar year 2008	$ 73	$ 32	$ 34

Assumptions

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
Weighted-average assumptions used to determine benefit obligations:	2007	2006	2007	2006	2007	2006
Discount rate	6.35%	5.95%	6.35%	5.95%	6.35%	5.95%
Rate of increase in compensation levels	4.34%	4.31%	5.00%	5.00%	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2007	2006	2007	2006	2007	2006
Discount rate	5.95%	5.75%	5.95%	5.75%	5.95%	5.75%
Expected long-term rate of return on assets*	8.50%	8.50%	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	4.31%	4.34%	5.00%	5.00%	N/A	N/A

* The expected rate of return on plan assets remained at 8.5 percent for the calculation of the 2008 net periodic pension cost.

The healthcare cost trend rate assumption for 2007 fiscal year benefit obligation determination and 2008 fiscal year expense is a 9 percent increase for 2007 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2013. The healthcare cost trend rate assumption for the 2006 fiscal year benefit obligation determination and 2007 fiscal year expense was a 10 percent increase for 2006 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2011.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1 percent increase in the healthcare cost trend assumption would increase the service and interest cost $0.1 million or 22 percent and the accumulated periodic postretirement benefit obligation $1.2 million or 17 percent. A 1 percent decrease would reduce the service and interest cost by $0.1 million or 17 percent and the accumulated periodic postretirement benefit obligation $0.9 million or 14 percent.

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
2008	$ 2,334	$ 129	$ 251	$ (65)	$ 186
2009	2,446	120	290	(73)	217
2010	2,581	111	343	(81)	262
2011	2,711	111	388	(89)	299
2012	2,803	93	414	(99)	315
2013-2017	16,372	443	2,561	(614)	1,947

Defined Contribution Plan

The Parent sponsors a 401(k) savings plan in which employees of the Company may participate. Participants may elect to invest up to 20 percent of their eligible compensation on a pre-tax basis, up to a maximum amount established by the Internal Revenue Service. The Company provides a matching contribution of 100 percent of the employee's annual contribution up to a maximum of 3 percent of eligible compensation. Matching contributions vest at 20 percent per year and are fully vested when the participant has 5 years of service with the Company. The Company's matching contributions were $0.6 million for 2007 and $0.6 million for 2006.

RELATED-PARTY TRANSACTIONS

Receivables and Payables

The Company has accounts receivable balances related to transactions with other BHC subsidiaries. The balances were $8.9 million and $1.9 million as of December 31, 2007 and 2006, respectively. The Company also has accounts payable balances related to transactions with other BHC subsidiaries. The balances were $3.2 million and $3.4 million as of December 31, 2007 and 2006, respectively.

Money Pool Notes Receivable and Notes Payable

In August 2005, the Company entered into a Utility Money Pool Agreement with the Parent and Cheyenne Light an electric and gas utility subsidiary of the Parent. Under the agreement, the Company may borrow from the Parent. The Agreement restricts the Company from loaning funds to the Parent or to any of the Parent's non-utility subsidiaries; the Agreement does not restrict the Company 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.

The Company through the Utility Money Pool had a net note receivable balance from Cheyenne Light of $10.3 million and $13.3 million as of December 31, 2007 and December 31, 2006, respectively. Advances under this note bear interest at 0.70 percent above the daily LIBOR rate (5.30 percent at December 31, 2007). Net interest income of $0.9 million and $0.3 million were recorded for the years ended December 31, 2007 and 2006, respectively.

Other Balances and Transactions

The Company also received revenues of approximately $1.9 million and $2.4 million for the years ended December 31, 2007 and 2006, respectively, from Black Hills Wyoming, Inc., an indirect subsidiary of the Parent, for the transmission of electricity.

The Company recorded revenues of $1.4 million and $3.3 million for the years ending December 31, 2007 and 2006, respectively, relating to payments received pursuant to a natural gas swap entered into with Enserco Energy, an indirect subsidiary of the Parent.

The Company purchases coal from Wyodak Resources Development Corp., an indirect subsidiary of the Parent. The amount purchased during the years ended December 31, 2007 and 2006 was $12.6 million and $10.8 million, respectively. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.

In order to fuel its combustion turbine, the Company purchased natural gas from Enserco Energy, an indirect subsidiary of the Parent. The amount purchased during the years ended December 31, 2007 and 2006 was approximately $4.5 million and $7.2 million, respectively. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.

Effective January, 2006 the Company pays the Parent for allocated corporate support service cost incurred on its behalf. Corporate costs allocated from the Parent were $11.3 million and $10.5 million for the years ended December 31, 2007 and 2006, respectively.

The Company has a transmission system reserve deposit from Black Hills Wyoming in the amount of $1.8 million and $1.7 million at December 31, 2007 and 2006, respectively, which is included in Deferred credits and other liabilities, Other on the accompanying Balance Sheets. Interest on the deposit accrues quarterly at an average prime rate (8.25 percent at December 31, 2007).

On January 1, 2006 the Company assumed the assets and liabilities of Mayer Radio, Inc., a subsidiary of the Parent. Results from the assumption of the business unit activity were not material to the Company.

COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements – PacifiCorp

In 1983, the Company entered into a 40 year power purchase agreement with PacifiCorp providing for the purchase by the Company of 75 MW of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduces the contract capacity by 25 MW (5 MW per year starting in 2000). The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants. Costs incurred under this agreement were $10.9 million in 2007 and $10.1 million in 2006.

The Company also has a firm point-to-point transmission service agreement with PacifiCorp that expires on December 31, 2023. The agreement provides that the following amounts of the Company's capacity and energy will be transmitted by PacifiCorp: 17 MW in 2005-2006 and 50 MW in 2007-2023. Costs incurred under this agreement were $1.2 million in 2007 and $0.4 million in 2006.

Long-Term Power Sales Agreements

- The Company has a ten-year power sales contract with the MEAN for 20 MW of contingent capacity from the Neil Simpson Unit #2 plant. The contract expires in February 2013.

- The Company has a power purchase agreement with MDU for the supply of up to 74 MW of capacity and energy for Sheridan, Wyoming from 2007 through 2016, which is subject to regulatory approval by the WPSC. The Company also has a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 MW of capacity and energy. The agreement renews automatically and requires a seven-year notice of termination. Both contracts are served by the Company and are integrated into its control area and are treated as part of the Company's firm native load.

Legal Proceedings

Ongoing Litigation

The Company is 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 the financial position, results of operations or cash flows of the Company.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	1,220,390	2,328,964	90.84%
6	501 Fuel	14,529,617	16,609,548	14.32%
7	502 Steam Expenses	3,177,307	3,421,379	7.68%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	981,272	1,169,326	19.16%
11	506 Miscellaneous Steam Power Expenses	1,406,717	1,207,550	-14.16%
12	507 Rents			
13				
14	TOTAL Operation - Steam	21,315,303	24,736,767	16.05%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	350,758	485,749	38.49%
18	511 Maintenance of Structures	219,938	190,830	-13.23%
19	512 Maintenance of Boiler Plant	3,813,471	3,402,608	-10.77%
20	513 Maintenance of Electric Plant	1,376,696	1,427,906	3.72%
21	514 Maintenance of Miscellaneous Steam Plant	725,776	762,523	5.06%
22				
23	TOTAL Maintenance - Steam	6,486,639	6,269,616	-3.35%
24				
25	**TOTAL Steam Power Production Expenses**	27,801,942	31,006,383	11.53%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

	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	57,216	54,582	-4.60%
27	547 Fuel	4,114,433	6,165,421	49.85%
28	548 Generation Expenses	326,422	360,158	10.34%
29	549 Miscellaneous Other Power Gen. Expenses	50,614	43,804	-13.45%
30	550 Rents			
31				
32	TOTAL Operation - Other	4,548,685	6,623,965	45.62%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	67,667	74,713	10.41%
36	552 Maintenance of Structures	14,339	5,865	-59.10%
37	553 Maintenance of Generating & Electric Plant	264,717	369,976	39.76%
38	554 Maintenance of Misc. Other Power Gen. Plant	10,282	23,806	131.53%
39				
40	TOTAL Maintenance - Other	357,005	474,360	32.87%
41				
42	**TOTAL Other Power Production Expenses**	4,905,690	7,098,325	44.70%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	56,227,686	49,377,537	-12.18%
46	556 System Control & Load Dispatching			
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	56,227,686	49,377,537	-12.18%
50				
51	**TOTAL Power Production Expenses**	88,935,318	87,482,245	-1.63%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	240,915	352,284	46.23%
4	561	Load Dispatching	845,809	928,777	9.81%
5	562	Station Expenses	32,277	42,342	31.18%
6	563	Overhead Line Expenses	10,948	12,607	15.15%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	7,257,358	8,162,489	12.47%
9	566	Miscellaneous Transmission Expenses	132,795	121,690	-8.36%
10	567	Rents			
11					
12		TOTAL Operation - Transmission	8,520,102	9,620,189	12.91%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	8,404	12,498	48.71%
15	569	Maintenance of Structures			
16	570	Maintenance of Station Equipment	31,713	33,503	5.64%
17	571	Maintenance of Overhead Lines	65,834	79,897	21.36%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant			
20					
21		TOTAL Maintenance - Transmission	105,951	125,898	18.83%
22					
23		**TOTAL Transmission Expenses**	8,626,053	9,746,087	12.98%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	674,707	771,641	14.37%
28	581	Load Dispatching	158,335	165,415	4.47%
29	582	Station Expenses	401,295	449,920	12.12%
30	583	Overhead Line Expenses	473,531	467,449	-1.28%
31	584	Underground Line Expenses	201,869	216,998	7.49%
32	585	Street Lighting & Signal System Expenses	199	136	-31.66%
33	586	Meter Expenses	316,843	245,879	-22.40%
34	587	Customer Installations Expenses	30,751	28,911	-5.98%
35	588	Miscellaneous Distribution Expenses	469,330	427,514	-8.91%
36	589	Rents	21,576	21,248	-1.52%
37					
38		TOTAL Operation - Distribution	2,748,436	2,795,111	1.70%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	32,015	36,060	12.63%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	120,007	132,647	10.53%
43	593	Maintenance of Overhead Lines	1,488,740	1,320,089	-11.33%
44	594	Maintenance of Underground Lines	115,823	123,311	6.47%
45	595	Maintenance of Line Transformers	14,847	10,591	-28.67%
46	596	Maintenance of Street Lighting, Signal Systems	116,700	137,074	17.46%
47	597	Maintenance of Meters	45,444	44,403	-2.29%
48	598	Maintenance of Miscellaneous Dist. Plant	31,227	31,234	0.02%
49					
50		TOTAL Maintenance - Distribution	1,964,803	1,835,409	-6.59%
51					
52		**TOTAL Distribution Expenses**	4,713,239	4,630,520	-1.76%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	17,047	25,934	52.13%
4	902 Meter Reading Expenses	431,402	454,478	5.35%
5	903 Customer Records & Collection Expenses	783,491	805,187	2.77%
6	904 Uncollectible Accounts Expenses	163,340	335,044	105.12%
7	905 Miscellaneous Customer Accounts Expenses	616,214	597,989	-2.96%
8				
9	TOTAL Customer Accounts Expenses	2,011,494	2,218,632	10.30%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	99,336	119,195	19.99%
14	908 Customer Assistance Expenses	824,962	737,854	-10.56%
15	909 Informational & Instructional Adv. Expenses	8,049	5,486	-31.84%
16	910 Miscellaneous Customer Service & Info. Exp.	43,575	52,019	19.38%
17				
18	TOTAL Customer Service & Info Expenses	975,922	914,554	-6.29%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision			
23	912 Demonstrating & Selling Expenses			
24	913 Advertising Expenses			
25	916 Miscellaneous Sales Expenses			
26				
27	TOTAL Sales Expenses			
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	10,149,424	9,759,385	-3.84%
32	921 Office Supplies & Expenses	3,165,932	3,673,451	16.03%
33	922 (Less) Administrative Expenses Transferred - Cr.	(43,980)	(32,675)	25.70%
34	923 Outside Services Employed	2,010,778	1,622,012	-19.33%
35	924 Property Insurance	644,904	673,134	4.38%
36	925 Injuries & Damages	1,273,880	1,087,181	-14.66%
37	926 Employee Pensions & Benefits	1,426,354	937,801	-34.25%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	310,141	355,550	14.64%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	358,222	431,704	20.51%
42	930.2 Miscellaneous General Expenses	587,437	644,725	9.75%
43	931 Rents	247,273	262,569	6.19%
44				
45	TOTAL Operation - Admin. & General	20,130,365	19,414,837	-3.55%
46	Maintenance			
47	935 Maintenance of General Plant	220,302	286,360	29.99%
48				
49	**TOTAL Administrative & General Expenses**	20,350,667	19,701,197	-3.19%
50				
51	**TOTAL Operation & Maintenance Expenses**	125,612,693	124,693,235	-0.73%

MONTANA TAXES OTHER THAN INCOME

Year: 2007

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel			
5	Montana PSC	4,800	5,550	15.63%
6	Franchise Taxes			
7	Property Taxes	51,580	59,970	16.27%
8	Tribal Taxes			
9	Montana Whosesale Energy Tax	2,496	2,930	17.39%
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50				
51	**TOTAL MT Taxes Other Than Income**	58,876	68,450	16.26%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2007

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

Company Name: **Black Hills Power, Inc.** **SCHEDULE 13**

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2007

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

Pension Costs

Year: 2007

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	50,340,250	49,311,391	-2.04%
8	Service cost	1,136,624	1,085,070	-4.54%
9	Interest Cost	2,923,207	2,719,962	-6.95%
10	Plan participants' contributions			
11	Amendments	(2,989,986)	(836,963)	72.01%
12	Actuarial Gain	(327,933)	156,403	147.69%
13	Acquisition			
14	Benefits paid	(2,144,879)	(2,095,613)	2.30%
15	Benefit obligation at end of year	48,937,283	50,340,250	2.87%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	46,916,331	43,858,906	-6.52%
18	Actual return on plan assets	8,043,709	5,899,334	-26.66%
19	Acquisition			
20	Employer contribution			
21	Plan participants' contributions	(348,887)	(746,296)	-113.91%
22	Benefits paid	(2,144,879)	(2,095,613)	2.30%
23	Fair value of plan assets at end of year	52,466,274	46,916,331	-10.58%
24	**Funded Status**	3,528,991	(3,423,919)	-197.02%
25	Unrecognized net actuarial loss	2,438,518	9,973,783	309.01%
26	Unrecognized prior service cost	559,743	663,104	18.47%
27	Prepaid (accrued) benefit cost	6,527,252	7,212,968	10.51%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	5.95%	5.75%	-3.36%
31	Expected return on plan assets	8.50%	8.50%	
32	Rate of compensation increase	4.31%	4.34%	0.70%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	1,136,624	1,085,070	-4.54%
36	Interest cost	2,923,207	2,719,962	-6.95%
37	Expected return on plan assets	(3,884,977)	(3,557,352)	8.43%
38	Amortization of prior service cost	103,361	103,362	0.00%
39	Recognized net actuarial loss	407,501	665,353	63.28%
40	Net periodic benefit cost	685,716	1,016,395	48.22%
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	961	898	-6.56%
48	Not Covered by the Plan	42	41	-2.38%
49	Active	569	522	-8.26%
50	Retired	178	172	-3.37%
51	Deferred Vested Terminated	172	163	-5.23%

Other Post Employment Benefits (OPEBS)

Year: 2007

	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	5.95%	5.75%	-3.36%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	10.00%	10.00%	
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	#VALUE!
11	Rate of compensation increase	4.31%	4.34%	0.70%
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13				
14				
15	**Describe any Changes to the Benefit Plan:**			
16				
17	TOTAL COMPANY			
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year	6,542,546	6,136,355	-6.21%
20	Service cost	210,670	249,271	18.32%
21	Interest Cost	398,195	397,883	-0.08%
22	Plan participants' contributions			
23	Amendments			
24	Actuarial Gain	50,934	97,784	91.98%
25	Acquisition			
26	Benefits paid	(210,961)	(338,747)	-60.57%
27	Benefit obligation at end of year	6,991,384	6,542,546	-6.42%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year			
30	Actual return on plan assets			
31	Acquisition			
32	Employer contribution			
33	Plan participants' contributions			
34	Benefits paid			
35	Fair value of plan assets at end of year			
36	**Funded Status**	(6,991,384)	(6,542,546)	6.42%
37	Unrecognized net actuarial loss			
38	Unrecognized prior service cost			
39	Prepaid (accrued) benefit cost	(6,991,384)	(6,542,546)	6.42%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	210,670	249,271	18.32%
42	Interest cost	398,195	397,883	-0.08%
43	Expected return on plan assets		-	
44	Amortization of prior service cost			
45	Recognized net actuarial loss	50,934	97,784	91.98%
46	Net periodic benefit cost	659,799	744,938	12.90%
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA			
49	Amount Funded through 401(h)			
50	Amount Funded through Other ___________			
51	TOTAL		-	
52	Amount that was tax deductible - VEBA			
53	Amount that was tax deductible - 401(h)			
54	Amount that was tax deductible - Other ___________			
55	TOTAL		-	

Other Post Employment Benefits (OPEBS) Continued

Year: 2007

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	760	712	-6.32%
3	Not Covered by the Plan			
4	Active	568	516	-9.15%
5	Retired	102	106	3.92%
6	Spouses/Dependants covered by the Plan	90	90	
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: 2007

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							

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	Mark T. Thies Executive Vice President and Chief Financial Officer						
3	Steven J. Helmers Senior Vice President-General Council						
4	Thomas M Olmacher President and Chief Operating Officer Utilities						
5	Linden Evans President & Chief Operating Officer						

***PLEASE REFER TO SCHEDULE 14A-Proxy Statement Pursuant to Section 14(a) of the Securities and Exchange Act of 1934 (pages 33-36)**

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, 2007 and December 31, 2006. We have no employment agreements with our Named Executive Officers. Amounts listed under the heading "Non-Equity Incentive Plan Compensation" represent amounts earned under the Short-Term Annual Incentive Plan for 2007 and 2006, respectively. The Compensation Committee approved the payout of the 2007 awards at its February 1, 2008, meeting and the awards were paid on February 26, 2008.

Based on the fair value of equity awards granted to our Named Executive Officers in 2007 and the base salary of our Named Executive Officers, base salary accounted for 36 percent to 51 percent of total compensation, short-term annual incentive accounted for 18 percent to 25 percent of total compensation and long-term incentive accounted for 31 percent to 43 percent of total compensation. Because the table below reflects the value of certain equity awards based on the Statement of Financial Accounting Standards 123(R), "Share-Based Payment," ("FAS 123(R)") value rather than the fair value, these percentages cannot be derived using the amounts reflected in the table below.

Name and Principal Position	Year	Salary	Bonus(1)	Stock Awards(2)	Option Awards(3)	Non-Equity Incentive Plan Compensation(4)	Change in Pension Value and Non-qualified Deferred Compensation Earnings(5)	All Other Compensation(6)	Total
David R. Emery Chairman, President and Chief Executive Officer	2007	$ 544,231	—	$ 921,030	—	$ 763,000	$ 312,524	$ 36,583	$2,577,368
	2006	$ 524,039	—	$ 327,766	$ 14,551	$ 551,250	$ 249,828	$ 40,276	$1,707,710
Mark T. Thies Executive Vice President and Chief Financial Officer(7)	2007	$ 288,377	—	$ 390,408	—	$ 230,960	$ 19,058	$ 19,776	$ 948,579
	2006	$ 279,885	—	$ 153,680	$ 14,239	$ 168,180	$ 55,459	$ 31,969	$ 703,412
Thomas M. Ohlmacher President and Chief Operating Officer—Non-regulated Energy	2007	$ 340,600	—	$ 766,103	—	$ 340,600	$ 13,645	$ 26,103	$1,487,051
	2006	$ 340,219	$ 32,000	$ 405,299	$ 34,085	$ 255,450	$ 223,970	$ 35,574	$1,326,597
Linden R. Evans President and Chief Operating Officer—Utilities	2007	$ 253,035	—	$ 432,649	—	$ 253,500	$ 53,952	$ 20,166	$1,013,302
	2006	$ 240,712	—	$ 151,114	$ 12,748	$ 181,050	$ 10,802	$ 20,088	$ 616,514
Steven J. Helmers Senior Vice President and General Counsel	2007	$ 259,408	—	$ 296,868	—	$ 181,790	$ 54,414	$ 15,231	$ 807,711
	2006	$ 251,819	—	$ 115,168	$ 9,612	$ 132,353	$ 109,035	$ 17,322	$ 635,309

(1) Mr. Ohlmacher's 2006 bonus reflects a $32,000 relocation bonus to compensate for additional state income taxes.

(2) Stock Awards represent the annual compensation expense related to restricted stock, restricted stock units and performance shares that have been granted as a component of Long-Term Incentive Compensation. The amount reported is the amount recognized for financial statement reporting purposes computed in accordance with FAS 123 (R), and therefore includes amounts for awards granted in prior years. Assumptions used in the calculation of these

amounts are included in Note 9 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007.

Mr. Ohlmacher turned age 55 in September 2006 which made him eligible for early retirement. Because our restricted stock and restricted stock units granted prior to December 10, 2007 fully vest at retirement, the fair value of $190,000 associated with Mr. Ohlmacher's awards granted in each of 2007 and 2006 was all recognized in the year of grant in accordance with FAS 123(R), rather than expensing the award over the normal three year vesting period.

(3) Option Awards represent the annual compensation expense related to stock options that have been granted as a component of Long-Term Incentive Compensation in prior years. The amount reported is the amount recognized for financial statement reporting purposes computed in accordance with FAS 123(R), and therefore includes amounts for awards granted in prior years. Assumptions used in the calculation of these amounts are included in Note 9 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007.

(4) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Annual Incentive Plan.

(5) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the increase in actuarial value of the Defined Benefit Pension Plan, Pension Restoration Benefit ("PRB"), Pension Equalization Plan ("PEP"), and 2007 Pension Equalization Plan ("2007 PEP") for the respective year. No Named Executive Officer received preferential or above-market earnings on nonqualified deferred compensation. The value attributed from each plan to each Named Executive Officer is shown in the table below. Mr. Evans was not a participant in the PRB or PEP in 2007 and 2006. Mr. Evans is the only Named Executive Officer participating in the 2007 PEP.

	Year	Defined Benefit Plan	Pension Restoration Benefit	PEP and 2007 PEP	Total Change in Pension Value
David R. Emery	2007	$ 6,366	$ 159,889	$ 146,269	$ 312,524
	2006	$ 13,444	$ 116,786	$ 119,598	$ 249,828
Mark T. Thies	2007	$ 6,897	$ 9,195	$ 2,966	$ 19,058
	2006	$ 11,200	$ 16,192	$ 28,067	$ 55,459
Thomas M. Ohlmacher	2007	$ 36,675	$ (18,858)	$ (4,172)	$ 13,645
	2006	$ 49,308	$ 109,399	$ 65,263	$ 223,970
Linden R. Evans	2007	$ 14,958	—	$ 38,994	$ 53,952
	2006	$ 10,802	—	—	$ 10,802
Steven J. Helmers	2007	$ 13,460	$ 13,020	$ 27,934	$ 54,414
	2006	$ 20,172	$ 16,389	$ 72,474	$ 109,035

(6) All Other Compensation includes amounts allocated under the 401(k) match, dividends received on restricted stock and unvested restricted stock units and perquisites. Perquisites provided to our Named Executive Officers include personal use of a Company vehicle and financial planning services for 2007 and 2006 and club dues in 2006 only.

	Year	401(k) Match	Dividends on Restricted Stock/Units	Total Perquisites	Total Other Compensation
David R. Emery	2007	$ 6,750	$ 22,233	$ 7,600	$ 36,583
Mark T. Thies	2007	$ 6,750	$ 8,774	$ 4,252	$ 19,776
Thomas M. Ohlmacher	2007	$ 6,750	$ 15,525	$ 3,828	$ 26,103
Linden R. Evans	2007	$ 6,750	$ 9,409	$ 4,007	$ 20,166

Steven J. Helmers	2007	$	6,750	$	6,714	$	1,767	$ 15,231

(7) Mr. Thies resigned from the Company on January 18, 2008. Mr. Thies's severance agreement is disclosed under the caption "Severance Agreement."

BALANCE SHEET

Year: 2007

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	663,262,046	664,721,391	0%
4	101.1 Property Under Capital Leases			
5	102 Electric Plant Purchased or Sold			
6	104 Electric Plant Leased to Others			
7	105 Electric Plant Held for Future Use			
8	106 Completed Constr. Not Classified - Electric	7,409,011	13,982,117	-47%
9	107 Construction Work in Progress - Electric	7,585,646	19,018,220	-60%
10	108 (Less) Accumulated Depreciation	(275,378,246)	(279,711,936)	2%
11	111 (Less) Accumulated Amortization			
12	114 Electric Plant Acquisition Adjustments	4,870,309	4,870,308	0%
13	115 (Less) Accum. Amort. Elec. Acq. Adj.	(2,371,999)	(2,523,403)	6%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	405,376,767	420,356,697	-4%
16				
17	**Other Property & Investments**			
18	121 Nonutility Property	5,618	5,618	0%
19	122 (Less) Accum. Depr. & Amort. for Nonutil. Prop.	(3,956)	(3,956)	0%
20	123 Investments in Associated Companies			
21	123.1 Investments in Subsidiary Companies			
22	124 Other Investments	3,725,605	3,934,711	-5%
23	125 Sinking Funds			
24	**TOTAL Other Property & Investments**	3,727,267	3,936,373	-5%
25				
26	**Current & Accrued Assets**			
27	131 Cash	1,218,463	2,028,950	-40%
28	132-134 Special Deposits			
29	135 Working Funds	4,625	4,175	11%
30	136 Temporary Cash Investments			
31	141 Notes Receivable	61,581	12,626	388%
32	142 Customer Accounts Receivable	14,602,459	16,565,623	-12%
33	143 Other Accounts Receivable	800,435	2,198,228	-64%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(250,000)	(388,368)	36%
35	145 Notes Receivable - Associated Companies	13,263,611	10,304,111	29%
36	146 Accounts Receivable - Associated Companies	1,934,682	8,882,287	-78%
37	151 Fuel Stock	6,479,782	4,025,206	61%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	11,045,234	11,525,086	-4%
41	155 Merchandise			
42	156 Other Material & Supplies	(412)		#DIV/0!
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed	53,940	77,553	-30%
45	165 Prepayments	884,740	6,173,396	-86%
46	171 Interest & Dividends Receivable			
47	172 Rents Receivable			
48	173 Accrued Utility Revenues	4,798,306	5,776,556	-17%
49	174 Miscellaneous Current & Accrued Assets	878,230	238,315	269%
50	**TOTAL Current & Accrued Assets**	55,775,676	67,423,744	-17%

BALANCE SHEET

Year: 2007

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Assets and Other Debits (cont.)**			
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	1,433,924	1,361,760	5%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	183	Prelim. Survey & Investigation Charges	766,152	616,078	24%
10	184	Clearing Accounts	192,534	404,419	-52%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	284,820	233,455	22%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	2,693,950	2,527,308	7%
16	190	Accumulated Deferred Income Taxes	24,593,586	15,569,776	58%
17		**TOTAL Deferred Debits**	29,964,966	20,712,796	45%
18					
19		**TOTAL Assets & Other Debits**	494,844,676	512,429,610	-3%

	Account Title		Last Year	This Year	% Change
20					
21		**Liabilities and Other Credits**			
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	23,416,396	23,416,396	
26	202	Common Stock Subscribed			
27	204	Preferred Stock Issued			
28	205	Preferred Stock Subscribed			
29	207	Premium on Capital Stock	42,076,811	42,076,811	
30	211	Miscellaneous Paid-In Capital			
31	213	(Less) Discount on Capital Stock			
32	214	(Less) Capital Stock Expense	(2,501,882)	(2,501,882)	
33	215	Appropriated Retained Earnings			
34	216	Unappropriated Retained Earnings	145,809,574	170,705,475	-15%
35	217	(Less) Reacquired Capital Stock	(932,044)	(1,277,097)	27%
36		**TOTAL Proprietary Capital**	207,868,855	232,419,703	-11%
37					
38	**Long Term Debt**				
39					
40	221	Bonds	133,365,000	131,410,000	1%
41	222	(Less) Reacquired Bonds			
42	223	Advances from Associated Companies			
43	224	Other Long Term Debt	21,854,229	21,807,473	0%
44	225	Unamortized Premium on Long Term Debt			
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.			
46		**TOTAL Long Term Debt**	155,219,229	153,217,473	1%

Company Name: Black Hills Power, Inc.

SCHEDULE 18

BALANCE SHEET

Year: 2007

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Total Liabilities and Other Credits (cont.)**			
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages			
9	228.3	Accumulated Provision for Pensions & Benefits			
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12		**TOTAL Other Noncurrent Liabilities**	-		
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	8,981,901	12,474,695	-28%
18	233	Notes Payable to Associated Companies	-		
19	234	Accounts Payable to Associated Companies	3,414,094	3,158,380	8%
20	235	Customer Deposits	639,048	636,712	0%
21	236	Taxes Accrued	12,718,535	4,575,823	178%
22	237	Interest Accrued	3,472,860	3,440,329	1%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	483,730	506,879	-5%
27	242	Miscellaneous Current & Accrued Liabilities	4,785,957	4,567,290	5%
28	245	Derivative Instrument Liabilities-Hedges		67,815	-100%
29		**TOTAL Current & Accrued Liabilities**	34,496,125	29,427,923	17%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	4,297,748	4,832,708	-11%
34	253	Other Deferred Credits	17,521,035	15,186,557	15%
35	255	Accumulated Deferred Investment Tax Credits	540,488	307,159	76%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	74,901,196	77,038,087	-3%
39		**TOTAL Deferred Credits**	97,260,467	97,364,511	0%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		494,844,676	512,429,610	-3%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2007

	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: 2007

	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	369,604	378,873	-2%
39	365	Overhead Conductors & Devices	415,751	415,751	
40	366	Underground Conduit	909	909	
41	367	Underground Conductors & Devices	15,834	15,834	
42	368	Line Transformers	43,484	43,484	
43	369	Services	3,367	3,367	
44	370	Meters	6,278	6,278	
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49	**TOTAL Distribution Plant**		1,333,084	1,342,353	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2007

	Account Number & Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment			
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment			
12	397 Communication Equipment	14,732	14,732	
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	14,732	14,732	
17				
18	**TOTAL Electric Plant in Service**	1,347,816	1,357,085	

MONTANA DEPRECIATION SUMMARY

Year: 2007

	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	1,316,049	373,062	352,243	
8	General	14,732	6,778	6,712	
9	**TOTAL**	1,330,781	379,840	358,955	

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	N/A	N/A	#VALUE!
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	4,988			
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**				11.73%
9					
10	Actual at Year End				
11					
12	Common Equity		60.27%		
13	Preferred Stock				
14	Long Term Debt		39.73%		
15	Other				
16	**TOTAL**		100.00%		

STATEMENT OF CASH FLOWS

Year: 2007

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	18,724,437	24,895,901	-25%
6	Depreciation	19,649,905	20,611,646	-5%
7	Amortization	473,040	455,770	4%
8	Deferred Income Taxes - Net	(2,566,464)	4,097,594	-163%
9	Investment Tax Credit Adjustments - Net	(233,329)	(233,329)	
10	Change in Operating Receivables - Net	200,410	(11,099,489)	102%
11	Change in Materials, Supplies & Inventories - Net	(3,269,441)	1,950,699	-268%
12	Change in Operating Payables & Accrued Liabilities - Net	7,676,972	(6,459,477)	219%
13	Allowance for Funds Used During Construction (AFUDC)	(405,019)	(601,108)	33%
14	Change in Other Assets & Liabilities - Net	2,281,533	(22,589,458)	110%
15	Other Operating Activities (explained on attached page)			
16	**Net Cash Provided by/(Used in) Operating Activities**	42,532,044	11,028,749	286%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(23,741,981)	(10,967,350)	-116%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets			
23	Investments In and Advances to Affiliates	(13,263,611)	2,959,500	-548%
24	Contributions and Advances from Affiliates	(946,478)		#DIV/0!
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	(203,536)	(209,106)	3%
27	**Net Cash Provided by/(Used in) Investing Activities**	(38,155,606)	(8,216,956)	-364%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt			
32	Preferred Stock			
33	Common Stock			
34	Other:			
35	Net Increase in Short-Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(1,995,808)	(2,001,756)	0%
39	Preferred Stock			
40	Common Stock			
41	Other:	(1,842,148)		#DIV/0!
42	Net Decrease in Short-Term Debt			
43	Dividends on Preferred Stock			
44	Dividends on Common Stock			
45	Other Financing Activities (explained on attached page)			
46	**Net Cash Provided by (Used in) Financing Activities**	(3,837,956)	(2,001,756)	-92%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	538,482	810,037	-34%
49	**Cash and Cash Equivalents at Beginning of Year**	684,606	1,223,088	-44%
50	**Cash and Cash Equivalents at End of Year**	1,223,088	2,033,125	-40%

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

SCHEDULE 24

LONG TERM DEBT

Year: 2007

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	Series Y	06/1988	06/2018	6,000,000	5,906,578	3,100,000	9.49%	311,084	10.03%
2									
3	Series Z	05/1991	05/2021	35,000,000	34,790,305	23,310,000	9.35%	2,251,338	9.66%
4									
5	Series AC	02/1995	02/2010	30,000,000	29,766,300	30,000,000	8.06%	2,418,000	8.06%
6									
7	Series AE	08/2002	08/2032	75,000,000	74,008,936	75,000,000	7.23%	5,455,581	7.27%
8									
9	2004 Pollution Control:								
10	Campbell Cty 4.8%	11/2004	10/2014	1,550,000	1,517,018	1,550,000	4.80%	77,974	5.03%
11	Campbell Cty 5.35%	11/2004	10/2014	12,200,000	11,964,016	12,200,000	5.35%	654,884	5.37%
12	Pennington Cty 4.8%	11/2004	10/2014	2,050,000	1,999,347	2,050,000	4.80%	103,125	5.03%
13	Weston Cty 4.8%	11/2004	10/2014	2,850,000	2,791,873	2,850,000	4.80%	143,365	5.03%
14									
15	1994 A Environ Improv Bomd	06/1994	06/2024	3,000,000	2,930,057	2,855,000	4.35%	124,398	4.36%
16									
17	Bear Paw Energy	06/2000	05/2012	1,078,000	1,078,000	302,473	13.66%	45,098	14.91%
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	TOTAL			168,728,000	166,752,430	153,217,473		11,584,847	7.56%

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

SCHEDULE 25

PREFERRED STOCK

Year: 2007

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

COMMON STOCK

Year: 2007

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

MONTANA EARNED RATE OF RETURN

Year: 2007

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service			
3	108 (Less) Accumulated Depreciation			
4	**NET Plant in Service**			
5				
6	Additions			
7	154, 156 Materials & Supplies			
8	165 Prepayments			
9	Other Additions			
10	**TOTAL Additions**			
11				
12	Deductions			
13	190 Accumulated Deferred Income Taxes			
14	252 Customer Advances for Construction			
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions			
17	**TOTAL Deductions**			
18	**TOTAL Rate Base**			
19				
20	**Net Earnings**			
21				
22	**Rate of Return on Average Rate Base**			
23				
24	**Rate of Return on Average Equity**			
25				
26	Major Normalizing Adjustments & Commission			
27	Ratemaking adjustments to Utility Operations			
28				
29				
30				
31				
32	Note: This schedule is not completed because			
33	Montana revenues represent less than			
34	1% of the Company's revenues.			
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: 2007

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	1,357
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	(359)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	998
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	1,552
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	1,552
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	1,552
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	13
36		Commercial	20
37		Industrial	2
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	35
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	80,305
45		Average Annual Residential Cost per (Kwh) (Cents) *	8.32
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	45
48		Gross Plant per Customer	38,774

MONTANA CUSTOMER INFORMATION

Year: 2007

	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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25						
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28						
29						
30						
31						
32	**TOTAL Montana Customers**					

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

MONTANA EMPLOYEE COUNTS

Year: 2007

	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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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: 2008

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

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2007

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	11	1900	352	259,470	60,161
2	Feb.	1	1900	361	241,120	57,434
3	Mar.	2	1900	326	238,991	58,909
4	Apr.	4	1000	302	224,619	54,284
5	May	18	1300	296	242,542	71,901
6	Jun.	25	1600	381	246,291	64,522
7	Jul.	24	1700	430	273,618	51,740
8	Aug.	9	1700	411	261,091	55,250
9	Sep.	4	1600	374	251,407	78,940
10	Oct.	24	1900	288	270,381	97,115
11	Nov.	29	1800	330	273,504	92,366
12	Dec.	11	1800	342	315,771	106,797
13	**TOTAL**				3098805	849419

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	1,758,280	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,678,138
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	90,617	for Resale	482,093
7	(Less) Energy for Pumping			
8	**NET Generation**	1,848,897	Non-Requirements Sales	
9	Purchases	1,279,005	for Resale	849,419
10	Power Exchanges			
11	Received	12,498	Energy Furnished	
12	Delivered	(47,704)	Without Charge	
13	**NET Exchanges**	(35,206)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	3,027,922	Electric Utility	11,665
16	Delivered	(3,021,813)		
17	**NET Transmission Wheeling**	6,109	Total Energy Losses	77,490
18	Transmission by Others Losses			
19	**TOTAL**	3,098,805	**TOTAL**	3,098,805

SOURCES OF ELECTRIC SUPPLY

Year: 2007

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	7,083
2					
3	Thermal	Ben French	Rapid City, SD	10	(240)
4					
5	Thermal	Ben French	Rapid City, SD	24	137,894
6					
7	Thermal	Osage	Osage, WY	35	233,663
8					
9	Thermal	Wyodak	Gillette, WY	69	56,074
10					
11	Thermal	Neil Simpson Complex	Gillette, WY	112	825,984
12					
13	Thermal	Neil Simpson Complex	Gillette, WY	39	55,025
14					
15	Thermal	Lange	Rapid City, SD	39	32,121
16					
17	Purchases	See Schedule 32			1,279,005
18					
19	Wheeling	See Schedule 32			6,109
20					
21	Total Interchange	See Schedule 32			(35,206)
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	**Total**			426	2597512

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2007

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

Company Name: Schedule 35a

Electric Universal System Benefits Programs

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

Company Name: Schedule 35b

Montana Conservation & Demand Side Management Programs

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

MONTANA CONSUMPTION AND REVENUES

Year: 2007

	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	$7,013	$6,344	85	76	13	13
2	Commercial - Small	$70,462	$27,588	853	280	20	20
3	Commercial - Large						
4	Industrial - Small	$1,474,385	$1,015,175	28,865	19,608	2	2
5	Industrial - Large						
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**	$1,551,860	$1,049,107	29803	19964	35	35