BLACK HILLS POWER, INC.
ASSETS AND OTHER DEBITS

Line No.	Description	FERC Acct #	December 31st 2004	December 31st 2005	March 2006
	Utility Plant				
1	Electric Plant in Service	101	$ 607,392,736	$ 638,453,677	$ 642,251,612
2	Completed Construction Not Classified	106	28,441,912	10,810,779	11,022,790
3	Construction Work in Progress	107	4,065,626	6,684,274	8,029,835
4	Gross Utility Plant		639,900,274	655,948,730	661,304,237
5	Accum. Prov. For Depreciation	108	(240,472,137)	(258,537,572)	(262,994,240)
6	Elec Plant Acquisition Adj.	114	4,870,308	4,870,308	4,870,308
7	Accum. Prov. For Amort. Of Acq Adj	115	(2,069,191)	(2,220,595)	(2,258,446)
8	Total Utility Plant		402,229,255	400,060,872	400,921,859
	Other Property and Investments				
9	Non-Utility Property	121	5,618	5,618	5,618
10	Res for Depr-Non-Utility Property	122	(3,956)	(3,956)	(3,956)
11	Net Non-Utility Property		1,662	1,662	1,662
12	L/T Notes Receivable	124	253,611	181,586	179,195
13	Other Investments	128	3,141,681	3,340,483	3,478,019
14	Total Other Property & Investments		3,396,954	3,523,730	3,658,876
	Current and Accrued Assets				
15	Cash	131	3,410,024	679,981	1,386,532
16	Working Funds	135	3,400	4,625	4,625
17	Temporary Cash Investments	136	133,399	-	-
18	Notes & Accts Receivable - Net	141-145;173	18,184,149	20,149,913	21,065,168
19	Accts Rec Assoc Company	146	890,550	1,964,490	1,099,196
20	Fuel Stocks	151	2,210,658	3,991,733	4,041,676
21	Material and Supplies	154-163	9,302,278	10,243,911	10,599,866
22	Prepayments	165	11,765,887	8,794,608	8,551,385
23	Other Current Assets	174, 176	29,838	191,680	31,000
24	Short Term Def Tax	190	862,319	1,027,493	940,653
25	Total Current & Accrued Assets		46,792,502	47,048,434	47,720,100
	Deferred Debits				
26	Unamortized Debt Expense	181	1,567,729	1,506,087	1,488,046
27	Preliminary Survey	183	333,936	-	-
28	Miscellaneous Debits	184-187	1,911,631	1,736,607	1,188,376
29	Other Regulatory Assets	182	4,172,405	4,061,620	4,061,620
30	Unamortized Loss on Reacquired Bond	189	3,064,215	2,879,082	2,832,799
31	Deferred Income Tax	190	4,981,106	5,467,517	5,431,317
32	Total Deferred Debits		16,031,022	15,650,912	15,002,159
33	Total Assets and Other Debits		$ 468,449,732	$ 466,283,949	$ 467,302,994

BLACK HILLS POWER, INC.
LIABILITIES AND OTHER CREDITS

Line No.	Description	FERC Acct #	December 31st 2004	December 31st 2005	March 2006
	Proprietary Capital				
1	Common Stock Issued	201	$ 23,416,396	$ 23,416,396	$ 23,416,396
2	Premium on Capital Stock	207	42,050,811	42,050,811	42,076,811
3	Capital Stock Expense	214	(2,501,882)	(2,501,882)	(2,501,882)
4	Unapprop. Retained Earnings	216	109,306,716	127,312,068	131,983,901
5	Other Comprehensive Income	219	(1,435,854)	(1,597,727)	(1,424,965)
6	Total Proprietary Capital		170,836,188	188,679,666	193,550,261
	Long Term Debt				
7	Bonds	221	137,274,999	135,319,999	135,319,999
8	Other Long Term Debt	224	21,895,035	21,854,229	21,843,130
9	Total Long Term Debt		159,170,034	157,174,229	157,163,129
	Current & Accrued Liability				
10	Notes Payable	224, 233	25,042,109	1,816,365	42,219
11	Accounts Payable	232	7,102,073	9,820,658	5,906,581
12	Acc Pay. Assoc Company	234	331,517	1,623,712	1,850,830
13	Customer Deposits	235	560,421	568,937	599,174
14	Taxes Accrued	236, 283	6,201,185	6,899,801	10,003,789
15	Interest Accrued	237, 233	3,555,554	3,557,457	2,452,379
16	Tax Collections Payable	241	458,849	473,733	456,715
17	Misc Current & Accrued Liab	242, 245	3,558,658	3,917,517	3,162,910
18	Total Current & Accrued Liability		46,810,366	28,678,180	24,474,597
	Deferred Credits				
19	Customer Advance for Construction	252	2,237,737	3,305,036	3,237,733
20	Other Deferred Credits	253	10,260,492	11,365,405	11,804,692
21	Acc Deferred Inv Tax Credits	254-255	4,056,329	3,480,446	3,334,040
22	Acc Def Inc Taxes - Property	281;282	66,234,843	65,396,210	65,849,335
23	Acc Def Inc Taxes - Other	283	8,843,744	8,204,777	7,889,206
24	Total Deferred Credits		91,633,144	91,751,874	92,115,007
25	Total Liabilities & Other Credits		$ 468,449,732	$ 466,283,949	$ 467,302,994

BLACK HILLS POWER, INC.
FOOTNOTES
For the test year ending December 31, 2005

The attached footnotes were prepared as part of the Company's FERC Form 1 for the year ended December, 31, 2005.

Substantially all of the accounting policies described in the footnotes are applicable for the test period.

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc. (the Company) is an electric utility serving customers in South Dakota, Wyoming and Montana. The Company is a wholly owned subsidiary of the publicly traded Black Hills Corporation (the Parent).

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, the recording of asset removal costs as accumulated depreciation rather than as a liability.

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 the Federal Energy Regulatory Commission (FERC).

The Company's electric operations follow the provisions of the Financial Accounting Standards Board (FASB) of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (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 would be an extraordinary non-cash charge to operations of an amount that could be material. Criteria that give rise to the discontinuance of SFAS 71 include increasing competition that could restrict the Company's ability to establish prices to recover specific costs and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews these criteria to ensure the continuing application of SFAS 71 is appropriate.

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.

AFUDC represents the approximate composite cost of borrowed funds and a return on capital used to finance the construction expenditures and is capitalized as a component of electric property. AFUDC was calculated at an annual composite rate of 4.2 percent and 9.8 percent during 2005 and 2004, respectively.

Depreciation

Depreciation is computed on a straight-line method over the estimated useful lives of the related assets. Depreciation provisions were equivalent to annual composite rate of 3.0 percent in 2005 and 2004, respectively.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America and to conform with accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases 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 contingencies. Actual results could differ from those estimates.

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, 2005, market adjustments related to fuel were $(0.2) million.

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 No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). SFAS 133 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 2005 or 2004.

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. 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.

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 described 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 billings to customers. Sales to Montana account for less than 1 percent of the Company's total electric revenue.

The Company's South Dakota, 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.

Supplemental Disclosure of Cash Flow Information

Cash paid during the year 2005 for interest was $11,993,000 and cash paid during the year 2005 for income taxes was $5,295,000.

(2) CAPITAL STOCK

The Company is a wholly-owned subsidiary of Black Hills Corporation.

(3) LONG-TERM DEBT

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 2006 through 2009, and $32.0 million for the year 2010.

(4) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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.

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

	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 157,215	$ 183,491	$ 159,206	$ 190,273

(5) 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 megawatt 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, 2005, the Company's investment in the Plant included $73.8 million in electric plant and $38.8 million 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 $6.1 million and $6.0 million for the years ended December 31, 2005 and 2004, 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 Power Cooperative owns a 65 percent interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie placed into service in the fourth quarter of 2003. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the Western Electricity Coordinating Council (WECC) region and the Mid-Continent Area Power Pool, or "MAPP" region. The total transfer capacity of the tie is 400 megawatts – 200 megawatts West to East and 200 megawatts 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 $0.2 and $0.1 million for years ended December 31, 2005 and 2004, respectively. As of December 31, 2005, the Company's investment in the transmission tie was $19.7 million, with $0.9

million of accumulated depreciation and is included in the corresponding captions in the accompanying Balance Sheets.

(6) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements – Pacific Power

In 1983, the Company entered into a 40 year power purchase agreement with PacifiCorp providing for the purchase by the Company of 75 megawatts of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduces the contract capacity by 25 megawatts (5 megawatts 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 $10.1 million in 2005 and $10.0 million in 2004.

In addition, the Company has a firm network transmission agreement for 36 megawatts of capacity with PacifiCorp that expires on December 31, 2006. Annual costs are approximately $0.9 million per year. The Company uses this agreement to serve the Sheridan, Wyoming electric service territory under our contract with Montana-Dakota Utilities Company.

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 capacity and energy be transmitted: 32 megawatts in 2001, 27 megawatts in 2002, 22 megawatts in 2003, 17 megawatts in 2004-2006 and 50 megawatts in 2007-2023. Costs incurred under this agreement were $0.4 million in 2005 and $0.4 million in 2004.

ɔng-Term Power Sales Agreements

- The Company has a ten-year power sales contract with the Municipal Energy Agency of Nebraska (MEAN) for 20 megawatts of contingent capacity from the Neil Simpson Unit #2 plant. The contract expires in February 2013.

- The Company has a contract with Montana-Dakota Utilities Company, expiring January 1, 2007, for the sale of up to 55 megawatts of energy and capacity to service the Sheridan, Wyoming electric service territory. The Company entered into a new power purchase agreement with MDU for the supply of up to 74 megawatts 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 megawatts 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

Forest Fire Claims

In September 2001, a fire occurred in the southwestern Black Hills, now known as the "Hell Canyon Fire." It is alleged that the fire occurred when a high voltage electrical span maintained by the Company broke, and electrical arcing from the ~evered line ignited dry grass. The fire burned approximately 10,000 acres of land owned by the Black Hills National ɔrest, the Oglala Sioux Tribe, and other private landowners. The State of South Dakota initiated litigation against the Company, in the Seventh Judicial Circuit Court, Fall River County, South Dakota, on or about January 31, 2003. The

Complaint seeks recovery of damages for alleged fire suppression and rehabilitation costs. A claim for treble damages is asserted with respect to the claim for injury to timber. A substantially similar suit was filed against the Company by the United States Forest Service, on June 30, 2003, in the United States District Court for the District of South Dakota, Western Division. The State subsequently joined its claim in the federal action. The State claims damages in the amount of approximately $0.8 million for fire suppression and rehabilitation costs. The United States Government's claim for fire suppression and related costs has been submitted at approximately $1.3 million. A trial date has been set for late 2006. The Company has denied all claims and will vigorously defend this matter, the timing or outcome of which is uncertain.

On June 29, 2002, a forest fire began near Deadwood, South Dakota, now known as the "Grizzly Gulch Fire." Before being contained more than eight days later, the fire consumed over 10,000 acres of public and private land, mostly consisting of rugged forested areas. The fire destroyed approximately 7 homes and 15 outbuildings. There were no reported personal injuries. In addition, the fire burned to the edge of the City of Deadwood, forcing the evacuation of the City of Deadwood, and the adjacent City of Lead, South Dakota. These communities are active in the tourist and gaming industries. Individuals were ordered to leave their homes, and businesses were closed for a short period of time. On July 16, 2002, the State of South Dakota announced the results of its investigation of the cause and origin of the fire. The State asserted that the fire was caused by tree encroachment into and contact with a transmission line owned and maintained by the Company.

On September 6, 2002, the State of South Dakota commenced litigation against the Company, in the Seventh Judicial Circuit Court, Pennington County, South Dakota. The Complaint seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A claim for treble damages was asserted with respect to the claim for injury to timber.

On March 3, 2003, the United States of America filed a similar suit against the Company, in the United States District Court, District of South Dakota, Western Division. The federal government's Complaint likewise seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A similar claim for treble damages is asserted with respect to the claim for injury to timber. In April 2003, the State of South Dakota intervened in the federal action. Accordingly, the state court litigation has been stayed, and all governmental claims will be tried in U.S. District Court.

The state and federal government claim approximately $5.3 million for suppression costs, $1.2 million for rehabilitation costs, and $0.6 million for timber loss. Additional claims could be asserted for alleged loss of habitat and aesthetics or for assistance to private landowners.

The Company completed its own investigation of the fire cause and origin and based upon information currently available, the Company filed its Answer to the Complaints of both the State and the United States government, denying all claims, and asserting that the fire was caused by an independent intervening cause, or an act of God. A trial date has been set for August 2006. The Company expects to vigorously defend all claims brought by governmental or private parties.

During the period of April 2003 through June 2005, various private civil actions were filed against the Company, asserting that the Grizzly Gulch Fire caused damage to the parties' real property. These actions were filed in the Fourth Judicial Circuit Court, Lawrence County, South Dakota. The Complaints seek recovery on the same theories asserted in the governmental Complaints, but most of the Complaints specify no amount for damage claims. The Company will vigorously defend these matters as well.

Additional claims could be made for individual and business losses relating to injury to personal and real property, and lost income, all arising from the Grizzly Gulch Fire. A trial date has been set for August 2006.

Although we cannot predict the outcome or the viability of potential claims with respect to either fire, based on the information available, management believes that any such claims, if determined adversely to the Company, will not have a material adverse effect on the Company's financial condition or results of operations.

PPM Energy, Inc. Demand for Arbitration

On January 2, 2004, PPM Energy, Inc. delivered a Demand for Arbitration to the Company. The demand alleges claims for breach of contract and requests a declaration of the parties' rights and responsibilities under an Exchange Agreement executed on or about April 3, 2001. Specifically, PPM Energy asserts that the Exchange Agreement obligates the Company to accept receipt and cause corresponding delivery of electric energy, and to grant access to transmission rights allegedly covered by the Agreement. PPM Energy requests an award of damages in an amount not less than $20.0 million. The Company filed its Response to Demand, including a counterclaim that seeks recovery of sums PPM has refused to pay pursuant to the Exchange Agreement. The Company denies all claims. The dispute was presented to the arbitrator in August 2005. The Company cannot predict the outcome of the decision.

Ongoing Litigation

The Company is subject to various other 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 or results of operations of the Company.

7) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plan

The Company has a noncontributory defined benefit pension plan (Plan) covering the employees of the Company. 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 securities. The Company uses a September 30 measurement date for the Plan.

Obligations and Funded Status

Change in benefit obligation:

	2005	2004
	(in thousands)	
Projected benefit obligation at beginning of year	$ 46,176	$ 44,803
Service cost	991	959
Interest cost	2,700	2,621
Actuarial (gain) loss	9	(182)
Discount rate change	1,630	—
Benefits paid	(2,122)	(2,025)
Asset transfer to affiliate	(592)	—
Mortality assumption change	519	—
Net increase	3,135	1,373
Projected benefit obligation at end of year	$ 49,311	$ 46,176

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

	2005	2004
	(in thousands)	
Beginning market value of plan assets	$ 39,844	$ 37,115
Benefits paid	(2,122)	(2,025)
Investment income	6,729	4,754
Asset transfer to affiliate	(592)	—
Ending market value of plan assets	$ 43,859	$ 39,844

Funding information for the Plan is as follows:

	2005	2004
	(in thousands)	
Fair value of plan assets	$ 43,859	$ 39,844
Projected benefit obligation	(49,311)	(46,176)
Funded status	(5,452)	(6,332)
Unrecognized:		
Net loss	12,915	14,860
Prior service cost	766	922
	13,681	15,782
Net amount recognized	$ 8,229	$ 9,450

Amounts recognized in statement of financial position consist of:

	2005	2004
	(in thousands)	
Net pension asset	$ 8,229	$ 9,450
Accumulated benefit obligation	$ 41,191	$ 38,302

The provisions of SFAS No. 87 "Employers' Accounting for Pensions" (SFAS 87) required the Company to record a net pension asset of $8.2 million and $9.5 million at December 31, 2005 and 2004, respectively and is included in the line item Other in Other assets on the accompanying Balance Sheets.

Components of Net Periodic Pension Expense

	2005	2004
	(in thousands)	
Service cost	$ 991	$ 959

Interest cost		2,700		2,621
Expected return on assets		(3,480)		(3,420)
Amortization of prior service cost		156		166
Recognized net actuarial loss		854		1,080
Net pension expense	$	1,221	$	1,406

Assumptions

Weighted-average assumptions used to determine benefit obligations:	2005	2004
Discount rate	5.75%	6.00%
Rate of increase in compensation levels	4.34%	4.39%
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2005	2004
Discount rate	6.00%	6.00%
Expected long-term rate of return on assets*	9.00%	9.50%
Rate of increase in compensation levels	4.39%	5.00%

*The expected rate of return on plan assets was changed from 9.00 percent in 2005 to 8.50 percent for the calculation of the 2006 net periodic pension cost. This change is expected to increase pension costs in 2006 by approximately $0.3 million.

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 and 10.0 percent for the 2005 and 2004 plan years, respectively. For determining the expected long-term rate of return for equity assets, the Company reviewed annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2005, 11.8 percent, 12.5 percent, 10.1 percent and 10.3 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 7.0 percent from 1962 to 2005, 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 treasury bonds.

Plan Assets

Percentage of fair value of Plan assets at September 30:

	2005	2004
Domestic equity	52.9%	59.7%

Foreign equity	40.6	34.5
Fixed income	3.4	2.6
Cash	3.1	3.2
Total	100.0%	100.0%

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

Asset Class	Target Allocation*
US Stocks	60% (with a variance of no more or less than 10% of target).
Foreign Stocks	30% (with a variance of no more or less than 10% of target).
Fixed Income	5% (with a variance of no more than 10% or no less than 5% of target).
Cash	5% (with a variance of no more than 10% or no less than 5% of target).

* The Plan's investment policy has been modified for 2006 to target an allocation of 50 percent U.S. stock, 25 percent foreign stock and 25 percent fixed income.

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-based assets. The policy provides that the Plan will maintain a passive core US Stock portfolio based on the S&P 500 Index. Complementing this core will be investments in US 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 does not anticipate any employer contributions to the Plan in 2006.

Estimated Future Benefit Payments

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

2006	$	2,163
2007		2,215
2008		2,303
2009		2,406
2010		2,558
2011-2015		14,763

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.

Obligations and Funded Status

		2005		2004
		(in thousands)		
Change in benefit obligation:				
Projected benefit obligation at beginning of year	$	1,886	$	1,886
Service cost		—		—
Interest cost		110		110
Actuarial (gains) losses		143		(8)
Benefits paid		(117)		(102)
Net increase		136		—
Projected benefit obligation at end of year	$	2,022	$	1,886
Fair value of plan assets at end of year	$	—	$	—
Funded status		(2,022)		(1,886)
Unrecognized net loss		858		762
Unrecognized prior service cost		3		3
Contributions		25		36
Net amount recognized	$	(1,136)	$	(1,085)

		2005		2004
		(in thousands)		
Amounts recognized in statement of financial position consist of:				
Net pension liability	$	(1,785)	$	(1,650)
Intangible asset		3		3
Contributions		26		36
Accumulated other comprehensive loss		620		526
Net amount recognized	$	(1,136)	$	(1,085)
Accumulated benefit obligation	$	1,785	$	1,650

The provisions of SFAS 87 required the Company to record an accrued pension liability of $1.8 million and $1.7 million at December 31, 2005 and 2004, respectively, and is included in Deferred credits and other liabilities, Other on the accompanying Balance Sheets.

Components of Net Periodic Benefit Cost

		2005		2004
		(in thousands)		
Service cost	$	—	$	—
Interest cost		109		110
Amortization of prior service cost		1		1
Recognized net actuarial loss		48		53

Net periodic benefit cost	$	158	$	164

Additional Information

	2005	(in thousands)	2004
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$ 94		$ 25

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30	2005	2004
Discount rate	5.75%	6.00%
Rate of increase in compensation levels	5.00%	5.00%
Weighted-average assumptions used to determine net periodic benefit cost for plan year	2005	2004
Discount rate	6.00%	6.00%
Rate of increase in compensation levels	5.00%	5.00%

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 2006.

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

Fiscal Year Ending		
2006	$	103
2007		109
2008		125
2009		112
2010		115
2011-2015		458

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 on the accumulated postretirement benefit obligation for the fiscal year ending December 31, 2005, was an actuarial gain of approximately $1.1 million. The effect on 2006 net periodic postretirement benefit cost will be a decrease of approximately $0.1 million.

Obligation and Funded Status

		2005		2004
		(in thousands)		
Change in benefit obligation:				
Accumulated postretirement benefit obligation at beginning of year	$	7,861	$	8,197
Service cost		292		300
Interest cost		465		485
Plan participants' contributions		403		339
Benefits paid and actual expenses		(469)		(516)
Net transfer out		(26)		—
Medicare Part D subsidy		(1,126)		—
Actuarial gains		(233)		(944)
Net decrease		(694)		(336)
Accumulated postretirement benefit obligation at end of year	$	7,167	$	7,861
Fair value of plan assets at end of year	$	—	$	—
Funded status		(7,167)		(7,861)
Unrecognized net loss		409		1,842
Unrecognized prior service cost		(208)		(227)
Unrecognized transition obligation		817		934
Contributions		13		23
Net amount recognized	$	(6,136)	$	(5,289)

Amounts recognized in statement of financial position consist of:

		2005		2004
		(in thousands)		
Accrued postretirement liability	$	(6,136)	$	(5,289)

Components of Net Periodic Benefit Cost

2005	2004
(in thousands)	

Service cost	$	292	$	300
Interest cost		465		486
Amortization of transition obligation		117		116
Amortization of prior service cost		(19)		(19)
Recognized net actuarial loss		74		144
Net periodic benefit cost	$	929	$	1,027

Assumptions

Weighted-average assumptions used to determine		
benefit obligations at September 30		
	2005	2004
Discount rate	5.75%	6.00%
Weighted-average assumptions used to determine net		
periodic benefit cost for plan year		
	2005	2004
Discount rate	6.00%	6.00%

The healthcare trend rate assumption for the 2005 fiscal year benefit obligation determination and 2006 fiscal year expense is 11 percent for 2005 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 for the 2004 fiscal year benefit obligation determination and 2005 fiscal year expense was 12 percent for 2004 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2011.

A 1 percent increase in the healthcare cost trend assumption would increase the service and interest cost $0.2 million or 23 percent and the accumulated periodic postretirement benefit obligation $1.3 million or 18 percent. A 1 percent decrease would reduce the service and interest cost by $0.1 million or 18 percent and the accumulated periodic postretirement benefit obligation $1.0 million or 15 percent.

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 2006.

Estimated Future Benefit Payments

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

Expected Gross Benefit	Expected Medicare Part D (Prescription Drug	Expected Net Benefit

Fiscal Year Ending	Payment	Benefit) Subsidy	Payments
2006	$ 227	$ (24)	$ 203
2007	250	(27)	223
2008	267	(31)	236
2009	303	(34)	269
2010	354	(36)	318
2011 - 2015	2,136	(236)	1,900

Defined Contribution Plan

The Company also sponsors a 401(k) savings plan for eligible employees. Participants elect to invest up to 20 percent of their eligible compensation on a pre-tax basis. The Company provides a matching contribution of 100 percent of the employee's tax-deferred contribution up to a maximum 3 percent of the employee's 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 totaled approximately $0.5 million for 2005 and $0.4 million for 2004.

(8) INCOME TAXES

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

	2005	2004
Current	$ 8,301	$ 5,731
Deferred	(2,558)	3,781
	$ 5,743	$ 9,512

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

Years ended December 31,	2005	2004
Deferred tax assets, current:		
Asset valuation reserve	$ 291	$ 319
Employee benefits	550	382
Items of other comprehensive income	76	—
Other	110	157
	1,027	858
Deferred tax liabilities, current:		
Prepaid expenses	192	155
Net deferred tax asset, current	$ 835	$ 703

Deferred tax assets, non-current:				
Plant related differences	$	949	$	598
Regulatory asset		898		1,025
ITC		271		362
Employee benefits		2,929		2,602
Items of other comprehensive income		217		184
Other		204		213
		5,468		4,984
Deferred tax liabilities, non-current:				
Accelerated depreciation and other plant related differences		65,459		66,371
AFUDC		2,640		2,712
Regulatory liability		1,422		1,460
Employee benefits		2,880		3,307
Items of other comprehensive income		—		22
Other		1,009		1,050
		73,410		74,922
Net deferred tax liability, non-current	$	67,942	$	69,938
Net deferred tax liability	$	67,107	$	69,235

.le following table reconciles the change in the net deferred income tax liability from December 31, 2004, to December 31, 2005, to the deferred income tax benefit (in thousands):

		2005
Decrease in deferred income tax liability from the preceding table	$	(2,128)
Deferred taxes associated with ITC		(517)
Deferred taxes associated with other comprehensive loss		87
Deferred income tax benefit for the period	$	(2,558)

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

	2005	2004
Federal statutory rate	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(1.7)	(1.5)
Deferred tax adjustments primarily related to plant-related changes in estimate	(8.2)	—
Research and development credit	—	—
Other	(0.9)	(0.4)
	24.2%	33.1%

(9) OTHER COMPREHENSIVE INCOME (LOSS)

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

	2005		
	Pre-tax Amount	Tax Expense	Net-of-tax Amount
Minimum pension liability adjustment	$ (94)	$ 33	$ (61)
Amortization of cash flow hedges settled and deferred in accumulated other comprehensive income (loss) and reclassified into interest expense	64	(22)	42
Net change in fair value of derivatives designated as cash flow hedges	(219)	76	(143)
Other comprehensive loss	$ (249)	$ 87	$ (162)

	2004		
	Pre-tax Amount	Tax Expense	Net-of-tax Amount
Minimum pension liability adjustment	$ 25	$ (9)	$ 16
Amortization of cash flow hedges settled and deferred in accumulated other comprehensive income (loss) and reclassified into interest expense	64	(22)	42
Other comprehensive income	$ 89	$ (31)	$ 58

(10) RELATED-PARTY TRANSACTIONS

Receivables and Payables

The Company has accounts receivable balances related to transactions with other Black Hills Corporation subsidiaries. The balances were $2.0 million and $0.9 million as of December 31, 2005 and 2004, respectively. The Company also has accounts payable balances related to transactions with other Black Hills Corporation subsidiaries. The balances were $1.6 million and $0.3 million as of December 31, 2005 and 2004, respectively.

Notes Payable - Affiliate

The Company has borrowings from its Parent, which are due on demand. Outstanding advances were $1.8 million at December 31, 2005 and $25.1 million at December 31, 2004. Advances under this note bear interest at 0.70 percent above the daily LIBOR rate (5.09 percent at December 31, 2005). Interest paid was $0.8 million and $0.1 million for the years ended December 31, 2005 and 2004, respectively.

In August 2005, the Company entered into a Utility Money Pool Agreement with the Parent; and Cheyenne Light, Fuel & Power, 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.

Other Balances and Transactions

The Company purchases coal from Wyodak Resources Development Corp., an indirect subsidiary of the Parent. The amount purchased during the years ended December 31, 2005 and 2004 was $10.1 million and $9.6 million, respectively.

In addition to the above transactions, 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, 2005 and 2004 was approximately $6.4 million and $2.7 million, respectively. These amounts are included in "Fuel and purchased power" on the Statements of Income.

The Company also received revenues of approximately $2.2 million and $1.1 million for the years ended December 31, 2005 and 2004, respectively, from Black Hills Wyoming, Inc., an indirect subsidiary of Black Hills Corporation, for the transmission of electricity.